Arnold Schwarzenegger
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COMMUNITY CHOICE AGGREGATION PILOT PROJECT APPENDIX G GUIDEBOOK

PIER FINAL PROJECT REPORT

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Preface

The California Energy Commission's Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

- PIER funding efforts are focused on the following RD&D program areas:
- Buildings End-Use Energy Efficiency
- Energy Innovations Small Grants
- Energy-Related Environmental Research
- Energy Systems Integration
- Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Transportation

California Community Choice Aggregation Guide is the interim report for the Community Choice Aggregation Pilot Program project (Contract Number 500-03-004) conducted by the Local Government Commission. The information from this project contributes to PIER's Renewable Energy Technologies Program.

For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/pier or contact the Energy Commission at 916-654-5164.

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Table of Contents

List of Figures

List of Tables

Abstract

Community choice aggregation (CCA) is authorized in California by Assembly Bill AB 117(Migden, Chapter 836, Statutes of 2002), which allows cities, counties, and groups of cities and counties to aggregate the electric load of the residents, businesses, and institutions within their jurisdictions to provide them electricity. The California Public Utilities Commission has developed rules for implementing community choice aggregation. Communities wishing to form a community choice aggregation program must file an implementation plan with the California Public Utilities Commission. A feasibility study will help determine whether community choice aggregation is a viable option for achieving community goals such as lower electric rates or higher renewable energy generation. This guidebook will assist local governments interested in establishing community choice aggregation programs. The guidebook provides information on meeting the requirements of the California Public Utilities Commission for community choice aggregation formation, undertaking feasibility studies and filing an implementation plan.

Keywords: community choice aggregation, CCA, electricity generation, renewable energy, AB 117, implementation plan

1.0 Introduction to Community Choice Aggregation

1.1. Purpose

This guidebook was developed to assist local governments interested in establishing a community choice aggregation (CCA) program. CCA allows a city or county or group of cities and counties to provide electricity for their constituents.

The book is funded by the U.S. Department of Energy and the California Energy Commission's Public Interest Energy Research (PIER) Program under a contract to investigate CCA feasibility and increased renewable energy development in California. The Local Government Commission is the main contractor and Navigant Consulting, Inc., is the technical consultant to the project.

The guidebook is divided into three sections, followed by appendices.

The first section includes provisions of the legislation enabling CCA and the California Public Utilities Commission's (CPUC) decisions implementing the law.

The second section provides information on what a community needs to do to investigate CCA.

The third section helps communities develop a CCA implementation plan.

The appendices include sample data request letters, the list of key assumptions used in the preliminary feasibility studies completed under this contract, and a table of CCA financing options.

1.2. Community Choice Aggregation Program Overview

Community choice aggregation includes electric power generation services only. The investor-owned utilities (IOUs) will continue to deliver the power over their transmission and distribution lines. All IOU customers within a CCA's territory have the option of buying electricity from the CCA or remaining as generation customers of the IOU by exercising their rights to *opt out* of the program.

1.3. Section Summary

Legislation was passed in 2002 that allows cities, counties, or groups of them to provide electricity to all of the customers within their jurisdictions by becoming community choice aggregators. Local governments can combine (aggregate) the electric loads of their constituents in order to produce or purchase electricity in bulk at a lower cost. All constituents are automatically customers of the CCA unless they opt out of the program and remain customers of their utility, Pacific Gas and Electric (PG&E), Southern California Edison (SCE), or San Diego Gas & Electric (SDG&E).

Local governments are interested in forming CCAs to have more control over the electricity consumed in their communities. They want to decide the type of electricity generated (many are interested in increasing the amount of renewable energy), and they want to control electric rates (most expect to charge less than the utilities). Other potential benefits include increased reliability and greater emphasis on energy efficiency.

CCAs will not be municipal utilities. They will not own the poles and wires; they will only provide the electricity itself. The investor-owned utilities will continue to deliver the electricity over their poles and wires. The IOUs will also provide customer service, meter reading, and billing.

Community choice programs exist in Ohio, Massachusetts, and Rhode Island. None is exactly like California's program. However, they all have been able to reduce rates for their customers.

CCA legislation has specific requirements for communities seeking to establish CCA programs, and the CPUC has developed procedures for doing so. A local government wishing to establish a CCA program must adopt a resolution stating that intent, and file an Implementation Plan with the CPUC.

1.4. What Is Community Choice Aggregation?

Assembly Bill 117 (Migden, Chapter 838, Statutes of 2002) grants cities and counties the authority to provide electricity for customers within their communities. They are permitted to aggregate (that is, combine) the loads of retail customers of the IOUs within their boundaries for the purchase and sale of electricity. A CCA will choose the electric power generation supply that will serve the community and set its own rates for that power.

All customers, including residential, commercial, and industrial, currently receiving electric service from an IOU, will be automatically enrolled in a CCA program, unless the customer notifies the CCA of its desire to opt out. Customers who chose to opt out remain generation customers of the IOU.

The CPUC was designated to decide how to implement AB 117 and established a rulemaking proceeding to do so.

1.5. Why Are Cities and Counties Investigating Community Choice Aggregation in California?

There are numerous benefits offered by CCA, primarily local control over the energy resources used by the community and the potential to provide electricity to customers at a lower overall cost.

Through CCA, a local government can develop a generation portfolio that diversifies fuel and technology types, improves the environment, and is more stable in cost. The CCA can choose to develop its own energy resources and thereby decide which resources will be developed and where.

A CCA can implement an aggressive program to increase the use of renewable energy and to promote energy efficiency. A CCA's local perspective and its primary mission to serve its constituents rather than maximize profits for shareholders places it in a position to implement energy efficiency programs in order to lower overall energy costs for the community, and/or develop potentially more expensive renewable energy projects to meet local demand.

Electricity suppliers will compete for the right to serve a CCA's load. California's experience with electric choice showed that suppliers were willing to offer discounts to large customers. For the most part, however, discounted rates were not offered to residential customers because of their relatively small loads compared to high marketing and transactions costs. The opt out feature of CCA eliminates most of the high marketing and transaction costs, which limited opportunities for residential and small commercial customers in the earlier de-regulated market that required opting into an aggregation plan.

Through community aggregation, small customers can obtain competitive electricity supplies directly from the wholesale market on a scale that was not feasible under previous direct access rules. Combining their individual loads makes small customers more attractive to electricity suppliers, especially when commercial and industrial loads are added. Cost savings can be passed on to customers through lower electric bills or can be used by the local governments to provide enhanced services to their constituents.

Other potential benefits include:

- Increased reliability of power supply.
- Customer access to democratically elected or appointed representatives and fiscal accountability.
- Development of energy rates for small business and incentives for community business retention and expansion.
- New revenue stream to the General Fund.
- Access to electric public good funds programs available to implement energy efficiency and conservation, which can create new local jobs and support the local economy.

For a more detailed discussion of benefits see Section 2.2.

1.6. Responsibilities of Community Choice Aggregators and Investor-Owned Utilities

A CCA will secure electricity for its customers under contracts for power or from its own power generation plants. The local IOU is required to provide delivery services over its existing transmission and distribution systems and to provide metering, billing, collection, and all traditional retail customer services (i.e., call centers, outage restoration, extension of new service). The IOUs will also continue to be responsible for the operation and maintenance of the transmission and distribution system that delivers electricity to residences and businesses.

The IOUs must deliver electricity to CCA customers under the same terms and conditions that they provide to their other customers. Customers of a CCA will pay the same charges for delivery services as customers that remain as full service, or *bundled* customers of the IOU. These delivery charges represent approximately one half of a typical household monthly electric bill.

A CCA customer will see no difference in service and will continue to receive a single bill for electricity, issued by and paid to the IOU. The IOU will collect the CCA's charges from its customers and transfer the collected funds to the CCA.

The IOU is authorized to assess a surcharge for some of its generation-related costs that were incurred on behalf of CCA customers prior to its creation and that might otherwise be shifted to the IOU's remaining customers. This surcharge is known as the *cost responsibility surcharge,* or CRS, and will be regulated by the CPUC. The CRS is discussed in greater detail in Section 1.11.

1.7. Community Choice Aggregation Is Not Municipalization

It is important to distinguish a CCA from a municipal utility and from an energy service provider. Each of these entities provides different services, has different responsibilities, and operates under different regulatory frameworks.

Forming a municipal electric utility, or *municipalization*, means replacing the existing IOU with a locally owned utility that provides both generation and delivery services. This includes the distribution system (i.e., the poles and wires) to deliver the power. A new municipal utility, or one expanding its territory, must either build this distribution system or acquire it through condemnation by eminent domain of the wires and poles of the IOU. This is an expensive and time-consuming process.

CCA allows local governments to provide generation services, control the content of the power supply, and set rates without having to provide delivery services or taking on the burden of managing a transmission and distribution system. A local government that implements a CCA program will procure electric power from wholesale markets or its own generation facilities. The local IOU will deliver that power to the CCA end-use customer across its transmission and distribution facilities.

An energy service provider (ESP) is a third party contractor that specializes in the business of energy purchases and sales and energy efficiency programs in a competitive market. An ESP must be registered with the CPUC as an authorized dealer of energy services. ESPs were authorized to sell electricity directly to customers after California deregulation instituted *direct access*. Direct access is the term used for electric customers who choose to purchase their electric commodity from a supplier other than their local investor-owned utility. Aggregating smaller customers was difficult for ESPs under the original deregulation scheme as each one had to choose to join the aggregation.

With the energy crisis of 2000-2001, new direct access service was suspended. Although no new direct access customers can be established and served by ESPs at this time, ESPs continue to operate in California for the customers they already had. ESPs are expected to be available as third-party contractors who could provide operations services for a CCA if they so choose.

1.8. Aggregation in Other States

Community choice programs currently operate in Ohio, Massachusetts, and Rhode Island. Following energy deregulation in Ohio, for example, around 90% of the residential and commercial customers who switched from their resident utilities did so to join a community choice program. The Northeast Ohio Public Energy Council (NOPEC) is the largest public aggregation program in the state with 118 member cities serving over 600,000 customers. Benefits to CCA customers are significant in this instance, as NOPEC's energy supply contract guarantees a discount ranging from 4–6% when compared with IOU rates. (www.nopecinfo.org)

In Massachusetts, the Cape Light Compact is a regional services organization made up of Barnstable and Dukes counties and all 21 towns of Cape Cod and Martha's Vineyard. The purpose of the compact is to represent and protect the interests of the nearly 200,000 customers in the region, and to negotiate lower cost electricity and other public benefits. (www.capelightcompact.org)

The Rhode Island Energy Aggregation Program is a consortium of 36 Rhode Island communities, which are organized under the auspices of the Rhode Island League of Cities and Towns for the purpose of purchasing the lowest cost electricity and other services from power suppliers. While currently only available for municipal facilities, the program saved its member cities and towns $2.685 million in the first four months of 2006. (www.rileague.org)

1.9. Why Was AB 117 Enacted?

Electric consumers were given a choice of electricity providers when the state deregulated its power market in 1998. At that time, a local government could choose the power supplier for its own operations. A few local governments chose renewable or *green* power supplies. Overall, less than 3 percent of California customers switched suppliers under this new deregulated market, largely because customers had to figure out for themselves which service provider was best for them. And while local governments could have aggregated their communities' loads, it would have been a difficult process, as each customer would have had to *opt in* one by one.

The energy crisis of 2000-2001 changed the rules again. The state stepped in to purchase power because California's two largest IOUs were on the verge of bankruptcy. Direct access was suspended and California consumers were no longer allowed to choose green power or any electricity provider other than their local, historical IOU. The only way to exercise any choice was to install on-site resources, such as solar systems.

Now under AB 117, local governments can combine the electric loads of their communities in a much more workable opt-out manner. They can have far greater authority over the source of the electricity that serves not only their own operations, but also the residents and businesses in their jurisdiction as well.

1.10. What Are the Rules for Implementing Community Choice Aggregation?

AB 117 requires that:

- Cities, counties, or groups of cities and counties wishing to establish CCA programs must do so by ordinance.
- CCA programs must offer electric service to *all* of their residential customers (Commercial and industrial customers may be offered service, but a CCA is not required to offer service to them).
- All CCA programs must offer a chance for their potential customers to opt out of the program and remain IOU generation customers.
- CCAs must develop implementation plans detailing the process and consequences of aggregation; the plans must contain all of the following:
    - An organizational structure of the program, its operations, and funding.
    - Rate-setting and other costs to participants.
    - Provisions for disclosure and due process in setting rates and allocating costs among participant.
    - The methods for entering and terminating agreements with other entities.
    - The rights and responsibilities of program participants, including consumer protection procedures, credit issues, and shutoff procedures.
    - Termination of the program.
    - A description of the third parties supplying electricity including financial, technical, and operational capabilities.
- A Statement of Intent must be filed with the implementation plan that addresses:
    - Universal access.
    - Reliability.
    - Equitable treatment of all classes of customers.
    - Any requirements established by state law or by the CPUC concerning aggregated service.
- The CPUC must develop a cost-recovery mechanism paid by customers of the CCA that will prevent shifting of costs to remaining IOU customers.
- The CPUC must set a date when a CCA program can commence.
- The IOUs must fully cooperate with any local governments that investigate, pursue, or implement CCA programs.

The CPUC was tasked with developing the rules for CCA implementation. It initiated Rulemaking 03-10-003 to do so. The rulemaking was split into two phases that were decided in December 2004 (D.04-12-046) and December 2005 (D.05-12-041). The decisions can be accessed at http://www.cpuc.ca.gov/ (click on "Online Documents," then "Final Decisions" and input the decision numbers above). Relevant portions of the decisions are cited throughout this guidebook. For a more detailed summary of the decisions, visit www.lgc.org/community/.

1.11. California Public Utilities Commission's Decision on Community Choice Aggregation Implementation

One of the most significant outcomes of the Rulemaking is the limited jurisdiction the CPUC has over the operations of CCAs. The CPUC's primary role is to regulate the service the IOUs provide to CCAs and their customers. The decision states: "Nothing in the statute directs the Commission [CPUC] to regulate the CCA's program except to the extent that its program elements may affect utility [IOU] operations and the rates and services to other customers."[1]

The CPUC has responsibility to ensure that a CCA's operations will not negatively impact, financially or otherwise, the service provided to customers who remain with IOUs. To that end, the CPUC will establish a cost responsibility surcharge for CCA customers to protect the remaining IOU customers. CCAs will have to file Implementation Plans and any other information requested by the CPUC to determine the CRS.

The CPUC will also:

- Certify that a CCA has filed an implementation plan.
- Set a start date for when customers can be transferred to CCA service.
- Oversee the relationship between the IOU and the CCA.

Other significant CPUC decisions include:

- Access to Utility Data

Local governments investigating CCA have the right to detailed electric billing and load data without it being masked in any way. The local government may be required to sign confidentiality agreements with the IOU for certain data.

- Cost Responsibility Surcharge

Customers of a CCA program cannot escape paying for past costs incurred by the IOUs or the Department of Water Resources (DWR) on behalf of the IOUs during the energy crisis of 2000 and 2001. All customers of the IOUs during that time will continue to be held responsible for those costs until they are paid off. Current IOU customers are

[1] California Public Utilities Commission Decision D.05-12-041, page 8.

paying for those costs as a part of their rates. As CCAs are established, their share of these costs will be collected in what is called the *cost responsibility surcharge*, or CRS.

The CRS will reflect the difference between the average portfolio price of electricity for each of the IOUs (including DWR contracts, DWR bond costs, and IOU higher priced contracts) and the market rate of electricity. As the market rate rises, the CRS declines. The average portfolio price is figured with all IOU customers, including those leaving for CCA service, and then compared to a market price formula using published electricity prices. The difference in costs can be attributable to CCA formation and is charged to CCA customers in the form of the CRS.

The CRS will be charged directly to customers, not to the CCA.

- Vintaging/Open Season

A CCA will be responsible for only those DWR and IOU liabilities that were current at the time the CCA began its operations. There will be different CRS charges applicable to CCAs depending on the year that a CCA begins serving customers. Thus, there will be different vintages of CCA charges.

The CPUC has stated that IOUs should incorporate CCA load losses into their planning efforts, just as they include any other forecast variable related to changes in supply or demand.

The *open season* process is meant to mitigate costs incurred by CCAs and the IOUs, and to provide a mechanism for coordinating the switching of customers. During the Open Season, a CCA can commit to a date on which responsibility for customer power purchases will switch from the IOU to the CCA. The CCA and the IOU will work jointly to forecast the amount of load that will switch on that date.

If an open season collaborative forecasting process fails, the CPUC has developed default opt out percentages for the first year of a CCA's operations of 5% for residential customers and 20% for non-residential customers. The purpose of the default opt out percentages is to estimate the cost to the IOU in the event a CCA misses its customer transfer date.

Participating in the open season is strictly voluntary and will occur annually. The decision permits negotiated agreements between a CCA and an IOU to assume some liability for power purchase strategies in exchange for relief from other risks.

The CRS will be determined based on the IOU power supply portfolio that exists at either the time the CCA begins serving customers or the date stated in a binding notice of intent provided by a CCA in an open season process.

- Phase In

A CCA may want to consider phasing in service to its customers for various reasons. First, phasing service can significantly reduce implementation risk by enabling a pilot program to work out any glitches before rolling the program out to all customers.

Secondly, a phase in program can help eliminate potential cash flow problems that might otherwise occur in the early years of CCA implementation.

The CPUC has stated that CCAs can legally phase in their programs. It also found that a phase in or pilot program may impose additional costs on an IOU that can be recovered in tariffs from the CCA. On the other hand, some phase in plans may reduce costs.

AB 117 does not prohibit a CCA from offering service to only a portion of the customers in its jurisdiction, with the exception that it must offer service to all *residential* customers. Presumably, the transfer of residential accounts could be phased in over time without violating the residential must offer requirement.

- Implementation Plan

The CPUC will use the Implementation Plan in its determination of the CRS for each CCA customer. The CPUC found nothing in the statute that directs it to approve or disapprove an Implementation Plan or modifications to it. Nor does the statute provide CPUC authority to de-certify a CCA or its Implementation Plan.

- Adding or Subtracting Communities in a CCA

Additions or deletions of cities or counties in a CCA program are permitted, but they could affect IOU operations and costs that would affect the CRS.

- California Alternative Rate for Energy (CARE) Discount

The California Alternative Rate for Energy (CARE) discount provides reduced rates for qualifying low-income customers. IOUs will continue to apply the CARE discount to all qualifying CCA customers. The discount will be calculated using all elements of a customer's bill, but the discount will be applied only to the delivery service rate. The discount will not be reflected in the CRS. CCAs can design rates that provide additional discounts if they choose.

- Future CCA Issues

Because CCA is a new program, the CPUC intends to initiate a new rulemaking proceeding to review the program within a year of the initiation of the first CCA's operation. In the meantime, CCAs and IOUs are encouraged to bring to the CPUC's attention problems with existing tariffs, rules, or policies adopted in the Decisions. This may be accomplished by consulting with the CPUC's technical staff or by filing petitions to modify orders issued in this proceeding.

1.12. What Is the Legal Process for Becoming a Community Choice Aggregator?

The process for becoming a CCA requires that the local government governing body(ies) adopt an ordinance proclaiming their decision to become a CCA, and they must file an Implementation Plan with the CPUC. A lot of time and effort should be spent before making these decisions, and after they are made, before commencing operations.

The San Joaquin Valley Power Authority (SJVPA) is a joint powers agency of 14 cities and counties in the Fresno Area. The SJVPA is the first entity in the state to file an Implementation Plan with the CPUC. To see the SJVPA's implementation plan visit: http://www.communitychoice.info/sjvpa/documents.php

2.0 Investigating Community Choice Aggregation Feasibility

2.1. Section Summary

Before undertaking the major steps associated with establishing a CCA program, a local government must define its objectives and determine whether or not the CCA program will help meet those objectives. It must also identify the expected benefits and risks of CCA and balance them within the context of CCA. If the local government, after carefully analyzing these considerations, finds that CCA will meet its objectives and will result in benefits that outweigh risks, the potential CCA must gather and analyze the necessary data to decide the financial and physical feasibility of the program. All this should be done in the public eye to ensure community support behind whatever decision is made.

This section of the guidebook will help communities navigate through and, ultimately, complete this process.

Community choice aggregation can provide many potential benefits including customer choice (CCA is currently the only way for a customer to choose any provider other than the utilities), local accountability, reduced energy costs, price stability, increased use of renewable energy, and increased energy efficiency.

CCA programs bear risks that are financial, political, administrative, and regulatory. These risks can be mitigated, but not entirely eliminated, by sound management practices. The major risk for a CCA program is the possibility that its rates will be higher than the utility's. Utility rates are unpredictable, and it is not feasible for a CCA to guarantee that at all times in the future its rates would be lower than the utility's. Higher rates may cause many customers to opt out of the CCA program and return to the IOU. Should that happen, the cost to the remaining CCA customers would rise, potentially causing them to want to leave as well.

A CCA program will need to perform energy supply management functions (produce or purchase electricity, forecast load, collect and process load information, coordinate scheduling with the grid operator), set rates, provide account services (exchange customer usage and billing information with the utility), and do other administrative functions (finance, legal, regulatory, contract management, public relations/marketing).

In order to test the economic feasibility of a CCA program, a community must determine its procurement priorities and other community objectives. It must then use this information combined with usage data from the utility, projected demographics, and fuel costs to determine what the cost to its customers will be over a period of years.

Since the transmission and distribution charges will be the same whether a customer buys electricity from the CCA or the utility, the comparison should focus on the generation portion of a customer's bill, including any exit fees allowed by the CPUC. In order to be prepared for the best and worst case scenarios, sensitivity analyses (for example, increasing or reducing the future price of natural gas by a certain percentage) should be tested.

The CRS, or exit fee, is supposed to protect the rates of the customers who remain with the IOU after a CCA program is established. It is the difference between the current market price of electricity and the average cost of the utility's generation resources.

Theoretically, a CCA will be able to purchase electricity at the current market rate; when the CRS is added to a customer's bill, the cost will equal that of the IOU. In order to provide electricity for less cost than the utility, a CCA will need to either purchase or produce electricity for less than the market rate. Buying electricity for less than the market rate may be difficult. But the tax-free financing authority of local governments may make electricity production less costly than the IOUs and other commercial generators. Also, CCAs can provide price stability to customers by buying electricity under longer term contracts, which provides benefits relative to the uncertainty inherent in utility rates.

CCAs, like other electricity providers, will be required to provide at least 20% renewable energy resources to their customers by 2010. The Energy Commission-funded pilot program tested four supply alternatives (20% renewable energy, all purchased; 20% renewable energy, some owned by CCA; 40% renewable energy, all purchased; 40% renewable energy, some owned by CCA). The results of the pilot program studies are specific to the communities studied; not all had the same savings or losses, although the trends were consistent in all instances. For example, the difference in cost between 20% and 40% renewables was minor, and CCA financing of generation was required to capture significant savings.

2.2. What Are the Potential Benefits of Community Choice Aggregation?

The potential benefits of CCA include:

- *Customer choice* in selecting or influencing the selection of energy resources serving the community.
- *Local accountability* for selection of energy resources, rate-setting, and administration of the CCA.
- *Reduced energy costs* through the negotiation of energy prices below those offered by investor-owned utilities, or from CCA-owned or financed generation.
- *Increased price stability* through a diversified energy supply portfolio, which includes long-term power purchase agreements and ownership of low-cost generating resources.
- *Affordable renewable energy* through economies of scale achieved by aggregating customer load and using public financing.

- *Environmental benefits* related to the procurement of energy from renewable and/or low-emission resources.
- *Ability to wheel electricity*, that is, to generate it in one location and use it in another.
- *Energy security* through the selection of reliable energy suppliers and/or construction of reliable generating resources.
- Opportunities to influence and implement effective *energy efficiency and demand side management programs* within the community.

2.2.1. Customer Choice

CCA provides choice to all electricity customers of the community. All customers have the option of being automatically enrolled in the CCA program or remaining with the IOU. Because direct access has been suspended by the California legislature for anyone who is not already a direct access customer, CCA is currently the only mechanism that allows customers to buy electricity from an entity other than an IOU.

One benefit that is important to many communities is the ability to use electricity generated from renewable energy resources and significantly exceed renewable energy standards imposed on IOUs by the state. CCA allows communities to weigh the costs and benefits of such decisions and, ultimately, to choose their preferred resource portfolio.

2.2.2. Local Accountability

Unlike IOUs, local governments are accountable to their citizens through locally elected officials whose tenures depend on serving the public good and supporting the interests of their communities. When compared with an IOU, the decisions of a local authority will be more transparent and will better reflect the desires of the community. An IOU will be subject to the preferences of its investors as well as the regulatory constraints imposed by the CPUC.

A CCA program allows communities to provide innovative energy services to customers that might not be explored by IOUs. Communities will be able to develop programs that respond to the concerns, needs, and values of their constituents.

One example could be formation of green pricing programs that provide customers with the option of choosing to use, and paying for, more renewable energy as a percentage of their total electric consumption. Other, more price sensitive customers could choose not to participate in such green pricing programs in order to maintain their lower rates.

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

The CCA 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. Incentive-laden pricing could be a factor in retaining businesses that might otherwise leave the community to seek locations with lower costs of doing business.

2.2.3. Reduced Energy Costs

Pilot project feasibility studies indicate that with the implementation of local CCA programs, electric cost savings could be 4–5% of total electric bills over a 20-year period. This savings can be used to lower rates for CCA customers, contribute to reserve or contingency funds, or augment the community's revenues for public services to its constituents.

CCAs can secure low-cost energy supplies by (1) negotiating low-cost, potentially long-term power purchase agreements with energy suppliers, and/or (2) using public financing to develop generating resources.

With respect to developing or investing in new generating resources, local governments have substantial financial advantages over IOUs. Three key advantages are:

- Because cities, counties, and Joint Powers Agencies are not-for-profit entities, rates will not need to reflect an investor return, whereas IOUs are allowed by the CPUC to include a profit margin in retail electric rates.
- 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.
- CCAs, as public organizations, will not be required to pay state or federal income taxes, another considerable savings when compared with IOUs.

In the short term, these financial advantages are somewhat offset by the increased costs of paying off the state's long-term bonds and power purchase contracts, which were entered into during the energy crisis of 2000-2001. After these costs are paid off, which will occur around the 2012 calendar year, CCAs may likely secure savings, particularly if they invest in or own new clean power plants.

The CPUC has authorized surcharges on customers of CCAs. These surcharges will be used to recover above market costs associated with the DWR's long-term power purchase agreements. These surcharges represent the difference, on a system average basis, of the average cost of the IOU's supply portfolio and the market price of electricity. In effect, the CRS shields the IOUs and their remaining ratepayers from the costs of losing customers to the CCA. The CRS will be determined annually by the utilities and the CPUC and reflected in the utilities' tariffs.

With respect to the CCA, this means the aggregating community must obtain electricity supplies at *below market prices* if it is to provide electricity cost savings to its customers during the period to which the CRS applies. There are two ways a CCA can obtain below market electricity prices:

- The CCA can negotiate for low-cost electric supplies from third party providers, some of whom may be willing to offer discounted prices in order to gain market share and position their firms for sales of other value added services.
- The CCA can utilize its ability to issue low-cost municipal bonds to develop or contract for generation resources or to purchase electricity from resources financed by other public agencies using low-cost municipal bonds.

While the opportunity for negotiation of low-cost power supplies will be circumstantial, the CCA's ability to secure public financing offers a competitive advantage over IOUs. The CCA, as a public agency, can finance generation projects at an effective cost of capital that is approximately one half that of an IOU or a typical merchant generation developer.

The municipal financing advantage is well-suited for development of renewable generation projects, as these projects generally have relatively high capital costs and low operating costs. By financing generation resources (conventional, such as natural gas fired, or renewable) or providing capital to prepay for electricity purchases, the CCA can obtain electricity at below market costs.

Once the CRS terminates at some point in the future, the CCA will compete directly against the IOU's then-current supply portfolio. By 2013, approximately 40% of the IOUs' supply portfolios will be comprised of power purchase contracts executed after 2005. Therefore, the cost competitiveness of the IOUs' portfolios in the post-CRS timeframe will largely depend on how efficiently they procure electricity supplies during the next several years. The conservative assumption is that the IOUs will procure electricity at prevailing market prices and that a CCA will need to bring its financing advantages to bear in order to obtain electricity cost savings in the post-CRS period.

While conceptually the imposition of the CRS eliminates cost savings opportunities, except to the extent a CCA can procure electricity at below market prices, in practice the customer mix of the CCA's program is an important determinant of whether cost savings opportunities exist. The CRS is calculated as if a CCA served a mix of customers identical to the overall mix of customers on the IOU's system. The actual customer mix within a CCA could be more heavily weighted towards commercial and industrial customers, which subsidize the residential customer class under the IOUs' current rate structures.

In the event that a CCA included a customer base that was heavily weighted towards commercial and industrial sectors, its residential customers would likely benefit from lower rates when compared with those of an IOU because some of the commercial and industrial margins could be used for lowering rates across the board. Conversely, if a CCA included a comparatively large percentage of residential customers, similar savings may not likely be achieved.

2.2.4. Increased Price Stability

Experts expect California's growing demand for electricity to be met by an increasing dependence on natural gas-fired power plants. California already imports about 84% of its natural gas from other regions, and our growing appetite for more electricity will require even more imported fossil fuels, including liquefied natural gas (LNG) from other countries. Because gas-fired generating resources account for the majority of the electricity consumed in the state, there is substantial price risk associated with much of our power supply. A CCA may be able to mitigate some of this price risk by developing or procuring energy from generating resources other than natural gas.

Renewable generating resources are not affected by fuel price fluctuations. In most instances, renewable energy has no fuel cost and is not subject to supply shortages that have occurred in natural gas markets. A combination of new renewable energy supply and long-term power purchase contracts will help achieve a higher level of price stability for homes and businesses, and will protect the local economy from fossil fuel price swings.

CCAs can also ensure rate stability by locking in electricity prices with long-term, low-priced energy contracts from a variety of sellers. Business customers in particular tend to value predictability in their energy costs.

Historically, IOU rates have exhibited periods of relative stability punctuated by periods of high rates (during times of crisis or when major investments in energy infrastructure are being made). Due to actions taken in response to the energy crisis of 2000-2001, as well as the imposition of California's statewide Renewables Portfolio Standard, the IOUs' current supply portfolios are much more heavily weighted toward fixed price contracts and renewable energy contracts than before the energy crisis. This should result in the IOUs' ability to charge ratepayers somewhat predictably increasing rates over the next several years. California is entering a period of major electricity infrastructure investments, and the addition of new utility-owned generation will also cause IOU rates to increase.

A CCA will make its electricity procurement decisions and set the rates it charges to customers. A CCA has a wider range of fiscal management alternatives than an IOU to control its electric supply costs and rates. For example, publicly owned (i.e., municipal) utilities commonly create rate stabilization funds using retained profits that enable them to weather short-term cost increases without the need to increase rates.

2.2.5. Affordable Renewable Energy

Because a CCA is a public agency, it can procure electricity from renewable resources financed with tax-exempt bonds and thereby obtain renewable energy at relatively low cost. Under a CCA program, homes and businesses can enjoy the benefits of non-polluting renewable energy resources at an affordable price.

Initial feasibility studies across the state for this pilot project suggest that many communities can meet up to half of their electricity demand with renewable energy resources (such as wind, solar, and geothermal steam), while still maintaining a modest savings over current IOU rates. That is more than double the renewable energy content the IOUs plan to include in their portfolios.

Currently, renewable generation comprises a relatively small portion of each IOU's generation portfolio. As adoption of these renewable technologies continues to increase, suppliers/builders of these technologies will need to increase production levels to meet demand. Manufacturing and technological enhancements/expansions required to meet this demand should lower the cost of producing renewable technologies, a benefit that will ultimately pass to the CCA and its constituents. However, the demand for renewable energy created by the Renewables Portfolio Standard (RPS) has driven up the price of renewable energy in the short term as utilities attempt to meet the 20% standard by 2010. Cost pressures should ease once the basic RPS requirements have been met.

2.2.6. Environmental Benefits of New Generation

By implementing a CCA program, a community can influence the development of new generation, either by offering contracts to suppliers for the purchase of energy or by direct involvement in developing new generating resources. Development of new generation, whether renewable or fossil fueled, will likely displace the production of older, less efficient generating sources.

According to the Energy Commission, approximately one-third of natural gas consumed in California is used for production of electricity. Today's natural gas-fired generation units can operate 30% to 40% more efficiently than similar generating technologies developed in the 1960s era, many of which are still online in California. For every kilowatt-hour (kWh) of electricity produced by a new generating resource, there will be up to 40% less natural gas consumed when compared to older units and even greater reductions in air emissions and greenhouse gases.

Furthermore, should a CCA choose to develop renewable generating resources, natural gas consumption and emissions will both decrease. As previously noted, kWh produced by a renewable energy resource requires no natural gas consumption and, depending on the renewable technology employed, air emissions may also be eliminated.

2.2.7. Self-Generation and Wheeling

A CCA program will provide a legal mechanism to transmit excess power from one location to another within the community, something not possible without CCA. Excess production from a CCA cogeneration or solar facility could be used to serve other customers within the community rather than being sold to an IOU or, in the case of net metered solar, lost to the system. The CCA program will enable the community to obtain greater value for its distributed generation facilities by diverting energy to community loads rather than back to the grid.

2.2.8. Energy Security

As the majority of new power plants in the United States are fueled by natural gas, the nation is increasingly becoming dependent upon imported natural gas and the economic risk associated with natural gas markets. The flurry of activity related to construction of new LNG facilities along the California and Baja California coast attests to the increased demand for imported natural gas.

Many people are concerned that during the next 10–20 years the United States will become as dependent on natural gas imports as it has become on imported oil. Such dependence raises a host of political, environmental, and security issues that potentially threaten the nation's vital interests.

By implementing a CCA program that relies more heavily on renewable energy resources, a community can ensure that the electricity consumption of customers participating in the program does not contribute to the potential problems associated with increased dependence on imported natural gas.

A CCA program can also promote greater reliance on local distributed generation facilities such as solar panels, on-site wind turbines, and co-generation facilities or fuel cells. Incorporating local distributed electric generation sources and remote renewable energy power plants helps diversify risk and increase service reliability.

2.2.9. Demand-Side Energy Efficiency

A CCA will be motivated to reduce overall energy costs. An integrated approach to supply planning, energy efficiency, and demand response should translate into greater energy savings. Energy efficiency and/or demand side management programs can be creatively structured to meet the unique needs of a community while yielding reductions in supply costs.

The CCA can use its revenue bonding capacity to finance worthy public benefits programs such as installation of rooftop photovoltaic systems and energy efficiency investments. It can repay the bondholders through charges included in monthly customer bills. The CCA's knowledge of its community will help improve the effectiveness of energy efficiency investments by targeting programs that support community preferences.

Current CPUC rules do not grant aggregators the right to administer public goods funding for energy efficiency programs. However, AB 117 does require that a proportional share of energy efficiency funding be spent in a community that forms a CCA program. Formation of a CCA program will obligate IOUs to ensure that communities are not underserved by energy efficiency programs that they oversee. The CCA may be able to seek authority to replace the IOU as administrator of energy efficiency programs by submitting a program application to the CPUC.

2.3. What Are the Potential Risks of CCA?

Communities that are investigating CCA face political, financial, and administrative risks, which may be mitigated with careful planning and use of experienced energy professionals. There are also regulatory risks that can impact a CCA program, but, so far, the CPUC process has been favorable to the CCA community.

2.3.1. Political

The primary risk when investigating CCA is political, especially if the IOU directly or indirectly opposes the CCA program. Whereas each of the local utilities has publicly supported CCA, there are always caveats that might cause them to oppose a specific CCA effort as it progresses toward an implementation plan.

Typical utility responses to local government energy initiatives are to urge local leadership to slow down for the purpose of avoiding pitfalls that may result from a lack of understanding of pertinent issues/considerations. The utility may criticize feasibility study assumptions and methods and may suggest that becoming a CCA entails great risk with little or no commensurate benefits.

Furthermore, the IOU may formally oppose elements of the implementation plan at the CPUC. For example, each of the utilities has voiced opposition to allowing CCAs to phase in operations over a multi-year period, and, as a result, phase in proposals contained in an implementation plan may be protested, or the utility may attempt to charge the CCA service fees for accommodating a phased CCA implementation.

In the extreme case, the utility might sponsor community organizations to oppose the program, as has been done by both SCE and SDG&E in their efforts to prevent municipalities from forming municipal utilities within their service territories. Communities should be realistic and anticipate some degree of opposition from their utility during their efforts. Utilities are prohibited from using ratepayer funds to compete with the CCA for customers; however, they are not restricted from using shareholder funds to market to customers. It should be noted that AB 117 requires utilities to fully cooperate with CCAs, and active opposition to a CCA's efforts would appear to violate the law.

Once a commitment to develop the implementation plan is made, an intensive effort will be required to decide the particulars of the CCA program. Choices must be made regarding program management and organizational structure, resources and suppliers, rates and customer protections, terms and condition of service, financing, and staffing. And all of this must be done in a very public setting, so that the residential, commercial, and industrial constituents are fully informed and allowed to participate in the process.

2.3.2. Financial

The major risk associated with forming a CCA program is the possibility that its rates exceed those charged by the respective IOU. This could cause customers to become dissatisfied with the program and/or return to IOU service.

The CCA's ratemaking authority and ability to raise rates, if necessary, should protect the CCA from the financial impacts of unanticipated cost increases. And if long-term program costs remain uncomfortably high, the CCA will have the option to terminate the program. If this becomes necessary, customers of the CCA will return to IOU service. To protect against potential costs associated with this, the CCA must set aside financial reserves to cover reentry fees in the event of program termination.

A CCA should not be formed unless there is a financial firewall that insulates the community's General Fund and taxpayers from financial liabilities of the CCA. However, the General Fund could be affected if the city council or board of supervisors voluntarily exposes the General Fund. A community's bond rating could also be indirectly affected if the CCA defaults on its bonds.

Unless outside financing is available for startup expenses, communities will need to allocate funds for this purpose. If the CCA is not able to successfully implement its programs and generate revenues, these startup funds would not be reimbursed.

Other factors influencing the cost-competitiveness of a CCA program will depend on:

- The mix of customers served by the CCA and the rate charged by the IOU for various customer classes.
- The composite load profiles (hour-by-hour energy consumptions) of the CCA's customers.
- The CCA's resource mix.
- The use of low-cost municipal bonds to finance generation development.
- Electricity prices and prices for other services negotiated with third-party electric suppliers.
- The IOU's generation costs and whether the increase in costs is passed on to CCA customers through the CRS.
- The costs charged by the IOU for implementation activities and transactions such as metering, billing, and customer services.

2.3.3. Administrative

Energy procurement and resource planning are subject to certain risks and uncertainties that must be managed by the energy supplier, whether it is the IOU or the operator of a CCA program. Forming a CCA program does not increase operational risks, but responsibility for their management transfers to the CCA and/or its suppliers.

The CCA will be able to obtain services from a variety of large, experienced suppliers to help manage the CCA program. Municipal utilities, for example, have been successfully managing commodity, credit, and operational risks for many decades, even during times of high commodity prices and supply shortages. Professional program management and application of standard industry risk management practices will be critical to the successful operation of a CCA and should allow a CCA to manage risks as effectively as an IOU.

The primary risks inherent in CCA operations are unanticipated events that may cause the CCA's costs to increase, or the rates of the IOU to decrease. In either case, the rates charged by the CCA would likely exceed those of the IOU, and CCA customers may become dissatisfied with the program. If such a situation were to persist, customers may leave the CCA and return to IOU service.

To the extent customers are not precluded from leaving the program, the CCA could face stranded costs as community members leave the CCA. This could lead to further increases in the per-kWh rate charged to customers, which would likely prompt additional customers to leave the program.

Appropriate program rules that limit customer switching or that impose exit fees to compensate remaining program customers for commitments made on behalf of the departing customers will mitigate the risk of losing customers.

However, if CCA customers find themselves obligated to a program with higher rates than those offered by an IOU (or other competitors), their dissatisfaction may be directed at those responsible for administering that program. Such a risk highlights the importance of clear disclosures in the customer notification process so that potential customers are clearly informed of their rights and obligations prior to taking service in the program.

The major variables and risks that might impact a CCA's costs are:

- The CRS will vary year-to-year. The CRS is inversely related to the market price of electricity. If market prices fall, the CRS will increase. If the CRS increases and the CCA has locked in electricity prices through long-term electricity or fuel contracts, a CCA's customers' total rates will increase.
- A CCA could overrely on long-term contracts with fixed prices, potentially resulting in a high-cost portfolio at a time when market prices are falling.
- A CCA could fail to secure its customer base, making debt financing difficult to obtain and exposing the CCA to stranded costs if customers opt out of the CCA program. Even with appropriate switching rules, large customers may go out of business or leave the area and leave behind costs that must be paid by remaining program customers.
- A CCA's energy suppliers could default on supply contracts (credit risk) at times when energy spot markets are high, forcing the CCA to purchase energy at relatively high prices.
- Customers could fail to pay the CCA's charges, and the CCA's credit policies and customer deposits may be insufficient to recover the uncollectible bills.
- The IOU could make changes to its rates that reduce the cost of generation services and increase the costs of delivery services or that shift costs among customer classes in a manner that disadvantages the customer mix served by a CCA.
- Other regulatory risks associated with changes in the rules and tariffs administered by the CPUC or in the wholesale markets regulated by the Federal Energy Regulatory Commission (FERC) could increase a CCA's cost of providing service. For example, they could require a CCA to use geographic-specific load profiles for electricity procurement. This could advantage coastal communities

that have relatively flat load profiles while hurting those located in hotter, inland climates with their peaks and valleys of electricity use.

Ultimately, the major operational risks are under the control of the program's management. Professional management is the key to mitigate the inherent risks involved with providing retail electric services.

The experiences of the IOUs during the energy crisis of 2000-2001 illustrate what can happen when risks are not properly managed. The IOUs' exposure to electricity price spikes during the energy crisis stemmed from a constraint imposed by the CPUC on their contracting abilities, coupled with a legislated rate freeze. Without these constraints, the financial situations of the IOUs would have been much different.

Because the utilities had divested nearly all of their natural gas-fired generating resources, they were each heavily short on resources and overly reliant on the spot market. When spot market prices spiked for an extended period of time, the cash drain forced the California Department of Water Resources (DWR) to take over electricity procurement responsibilities from the utilities.

Customers of SDG&E were not protected by the rate freeze and suffered from excessive rates as SDG&E was able to pass through its costs of procuring electricity from the spot markets. PG&E and SCE were unable to raise rates and experienced financial devastation.

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

2.3.4. Regulatory

Decisions by regulators could cause cost increases for a CCA program. A CCA may participate in regulatory proceedings at the CPUC or FERC in an effort to influence the regulatory process, which may or may not protect its interests and those of its customers.

Typically, associations are formed among entities with common interests. These associations participate on behalf of their constituents during the regulatory process to influence regulators. The amount of influence wielded in the regulatory process depends on the level of influence of the association's membership as well as the number of resources the association is able to devote to such efforts.

To some extent, the degree to which regulatory risk can be managed depends upon the prevalence of CCA throughout the state. If CCAs become widespread, with many communities being directly impacted by CPUC decisions, the CPUC is less likely to make decisions that impose additional costs on aggregators than if only one or two communities are affected.

2.3.5. Risk Mitigation

The risks of forming a CCA program evolve as a community begins its implementation planning process and then progresses to startup of program operations. The community's risk exposure also depends greatly upon the implementation approach it chooses.

Each of the above risks can be mitigated, although not altogether eliminated. A CCA can develop its program in such a way that it would be exposed to very little risk. Electricity supply contracts can be structured to transfer many of the risks to the suppliers.

Table 2-1 below describes basic risk management techniques for each of the primary risks associated with operating a CCA program.

Table 2-1. Risk management strategies

Risk	Mitigation
Cost Responsibility Surcharge Volatility	Use shorter duration supply contracts to offset CRS risk. If market prices decrease, the CCA's supply portfolio costs will also decrease, offsetting the increase in the customer's CRS payments to the IOU.
Commodity Price Volatility	Diversify supply portfolio by using contracts with various terms, multiple suppliers, and renewable energy and conventional generation. Transfer commodity price risks to energy suppliers through fixed-priced contracts or guaranteed discount pricing.
Customer Attrition	Establish exit fees following the free opt-out period. Negotiate term contracts with large customers.
Credit Risk	Perform periodic credit and exposure monitoring; ensure supplier diversity; maintain collateral and surety instruments. Require deposits from customers and return customers to utility for failure to pay bills.
Utility Rate Changes and Other Regulatory Risks	Participate in CPUC process to prevent shifting of costs to program customers.

Source: Navigant Consulting, Inc.

Physical and financial reserves are also important components of a CCA program that reduce program risk. Industry rules dictate certain reserve requirements for all electricity suppliers to protect the integrity of the system and to ensure reliability.

Like other energy suppliers, CCA programs will need to provide physical reserves to ensure reliable operation of the electric grid. The California Independent System Operator (California ISO) requires load-serving entities to maintain operating reserves (6%–8% of load) and regulating reserves (2.5%–5%) that can be quickly called upon in the event that the system experiences outages or electricity consumption unexpectedly increases. Load-serving entities can arrange for their own reserves, or the California ISO will charge the load-serving entity for the costs of reserves procured on its behalf. The costs of these reserves should be included as an expense item when performing a feasibility analysis.

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

A CCA program should maintain financial reserves in the form of rate stabilization funds or other reserve funds required by banks to support debt financing. Rate stabilization funds are maintained at the discretion of program management and the program's governing board. These funds are used to offset financial impacts to customers in the event of short-term cost increases and accrue cash for future capital expenditures.

To the extent that debt financing is used to fund capital expenditures, banks will require minimum debt service reserves equal to approximately 10% of the amount borrowed and will also impose minimum debt service ratios. These financial reserves are included in program rates, but these funds are an asset of the program that will ultimately be accessible for future rate reductions or other program purposes.

Communities can phase in implementation of CCA to help ensure a smooth transition for customers that join the program. Although a program's financial viability should not be dependent upon a phased implementation, a phase in could reduce implementation risk and could contribute to the program's financial benefits during the initial startup stage.

An example of phased implementation could be the initial offer of program energy to non-residential customers during a pilot phase of six months to one year. Based on successful operation during the pilot phase, the program could then offer its energy to all customers in its jurisdiction.

By initiating a CCA program with non-residential customers, the number of transactions (account transfers, monthly billing, etc.) that must be completed will be less than in a non-phased implementation. In this phased implementation scenario, the program will be able to work out any startup kinks while dealing with a much lower volume of transactions/customers than in a non-phased approach.

Another benefit of the phased implementation model is that non-residential customers are higher-margin customers when compared to the residential customer class, so the initial phase in period would provide greater margins for the program to help cover program startup costs. A CCA must comply with the legal requirements of AB 117 that require the eventual offering of program services to all residential customers.

2.4. What Are the Elements of a Community Choice Aggregation Program?

A CCA program will include all the activities needed to procure electricity for end-use customers, schedule delivery of the electricity, conduct financial settlements for wholesale electricity purchases and sales, determine the costs charged to individual customers, and interface with the IOU that provides billing, metering, and related services to CCA customers. These activities can be grouped into the broad categories described below.

2.4.1. Portfolio Operations

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

Electricity Procurement

The essential purpose of a CCA is to supply electricity to its customers. As an aggregator, the CCA can choose from various types of resources and wholesale electricity products that reflect the community's values related to cost certainty, environmental considerations, and cost effectiveness.

A variety of generation resources or power purchase contracts can be employed to provide for the time-varying load requirements of the CCA program. The pattern of aggregate electricity usage typically follows daily, weekly, and seasonal cycles. These cycles typically peak daily during the afternoon hours and seasonally during the summer months.

The CCA must consider these load patterns when assembling a supply portfolio that will match resources to the aggregate load shape of its customer base. Different types of generation resources and supply contracts can be used to meet base load requirements, intermediate resource needs, and peaking load requirements. These concepts are illustrated in Figure 2-1. The jagged line on the graph represents the electric load for this community for one week, starting on Sunday.

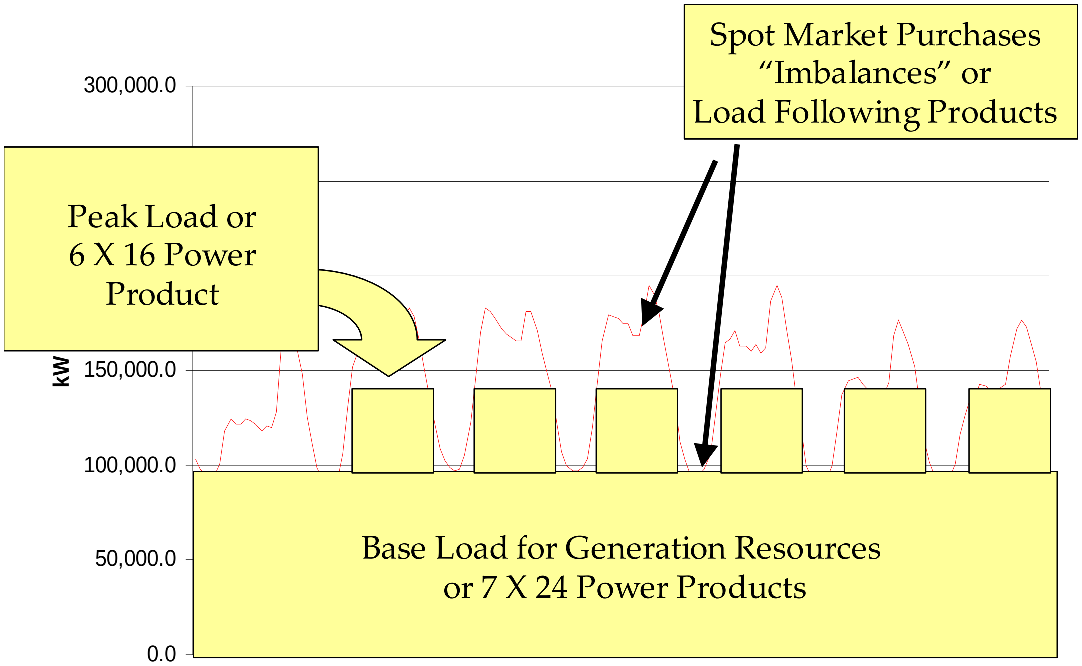

Figure 2.1: Supply portfolio matched to load shape

Source: Navigant Consulting, Inc.

A typical supply portfolio would utilize generation owned by the CCA or long-term contracts for the majority of projected base load requirements. These base load resources would be supplemented with intermediate resources or peak products as well as short-term contracts covering the additional seasonal load requirements of the portfolio, typically in the third quarter (July-September) of each year. Spot market purchases and sales are used to fill the load requirements that remain after using both long-term and short-term contracts and/or CCA-owned generating resources.

Risk and Credit Management

Risk management techniques need to be employed to reduce the CCA's exposure to volatile energy markets and to insulate customer rates from sudden changes in wholesale market prices. Credit monitoring must also be performed to keep abreast of changes in a supplier's financial condition and credit rating.

Common practice in the energy industry is to periodically calculate the financial exposure to a specific supplier by comparing the value of the supply contract to the contractual price. Exposure to suppliers is greatest when the contractual price is low relative to market prices, and the risk of default becomes a concern (in this instance, supplier default would require the CCA to procure energy at market prices, which when higher than contract prices would require the CCA to raise customer rates or offset them with reserve funds).

Collateral and other security instruments, such as letters of credits or surety bonds, are commonly used to manage credit risks between wholesale electricity buyers and sellers.

Load Forecasting and Data Collection

The CCA will be required to provide energy for each hour of the day, either through self-generation or supply contracts. In performing electricity procurement functions, accurate load forecasts, both long-term (for resource planning) and short-term (for the electricity purchases and sales needed to maintain a balance between hourly resources and loads) must be developed.

To develop both long-term and short-term energy procurement plans, a CCA may use off-the-shelf and/or customized forecasting applications that will model future energy demand based on a range of detailed assumptions, including historical load data provided by the IOU. Subject matter experts may also be hired by the CCA to assist with the development and interpretation of such forecasts.

By regularly preparing and monitoring these short- and long-term forecasts in relation to actual customer load, the CCA will be able to fine-tune its procurement strategies to meet the needs of its customers while minimizing unnecessary energy purchases (which would result in selling energy, often at a financial loss, to a third party or back to the grid) or spot purchases.

An accurate record of total time-of-day specific electricity demand and energy usage is essential. Lacking this, the CCA operator is required to rely on the IOU's recorded usage for each individual customer.

All customer classes are not metered in the same way. Residential and small commercial consumers (electric demand less than 20 kilowatt [kW]) typically have simple meters capable of metering only cumulative energy consumption. Medium commercial customers (electric demand in the range of 20–500 kW) are typically metered with energy and demand meters, but still lack time-of-day recording. Large commercial and industrial customers (electric demand greater than 500 kW) are typically equipped with data recording meters that record electric demand in 5, 10, or 15 minute intervals (interval data recording meters).

Without a time-of-use record of energy consumed, the CCA will have to rely on typical rate-class load profiles. The California ISO allows use of load profiles that are approved by the CPUC for scheduling and settlement. These load profiles represent the average or typical customer and not the CCA's actual customers. To date, the CPUC has approved the use of rate-class load profiles for use by the utilities and energy service providers for electricity scheduling and settlement. The IOUs have opposed proposals that CCAs be allowed to use area-specific load profiles for these purposes.

CCAs have the option, under the law, to meter electricity supplied to their territories to obtain an accurate record of aggregated loads. The IOU is required to install, maintain, and calibrate metering devices at mutually agreeable locations within or adjacent to the

CCA's political boundaries at the request and at the *expense* of the CCA. The IOU will also be required to read the metering devices and provide the data collected to the CCA at the aggregator's expense. Assessing the size, type, location, quantity, and installation cost of such CCA wholesale metering will require an analysis of the IOU's distribution system. At this time, it is not clear to what extent the CPUC or the California ISO would have to approve the CCA's use of boundary meters for electricity scheduling and settlement.

Scheduling Coordination

Scheduling coordination costs are associated with electric supply transactions with the California ISO. All customer meters must be represented by a California ISO-certified scheduling coordinator. The scheduling coordinator submits schedules to the California ISO of hourly electric demands and supply resources on behalf of the CCA.

The scheduling coordinator is responsible for costs associated with energy imbalances between actual hourly loads and actual hourly deliveries from the resources it represents. It is also responsible for the costs of reserves and other ancillary services provided by the California ISO that are necessary for reliable operation of the transmission system.

A CCA has several choices for obtaining services of a scheduling coordinator. Some companies act as independent scheduling coordinators and charge fees for their services. Other companies, such as power marketers or energy service providers, will provide scheduling coordination services as part of a larger package of energy services, including wholesale electricity supply, load forecasting, and risk management. The charges for providing scheduling coordinator services are bundled into the overall cost of electricity provided by the supplier.

It is also possible for the CCA itself to become a California ISO-certified scheduling coordinator, which requires acquisition of specialized software, completion of certification training conducted by the California ISO, and continuous staffing of a scheduling desk for round-the-clock, or 24 x 7, operations.

2.4.2. Rates

Rate design is the process of determining the charges that will be applied to customer electricity usage. Rate schedules define the charges for each kWh, kW, or other unit of electric service. There may be one or more rate schedules that are applicable to each customer class.

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

Ultimately, rates are established to recover the CCA's revenue requirement. Because rates are established based on forecasted customer demand, energy costs, and other considerations, the CCA will need to periodically adjust rates, based on differences between actual and forecasted data, to maintain sufficient revenues.

The revenue requirement is split between the classes of customers in the CCA program, such as residential, small commercial, medium commercial, large industrial, agricultural, and street lighting customers. Revenue allocation is typically performed on a cost of service basis, so that rates reflect the differences in the CCA's costs to serve each customer class.

The CCA may use load research to estimate customer class load profiles and cost of service by using sampling techniques. Load research meters (that can record customer electricity consumption in 5–15 minute intervals) are installed on a small sample of customers within each rate class. Alternatively, the CCA may use the customer class load profiles created by the IOU.

2.4.3. Account Services

The CCA must be able to exchange customer usage (meter) data electronically with the IOU using the utility's standard electronic data interchange procedures and formats. The CCA must also receive and process customer payments collected by the IOU.

Aggregators may also need to calculate individual customer bills. If this is necessary, the CCA will need to provide these calculated amounts to the IOU in an appropriate data format and by the prescribed timeline associated with IOU billing cycles.

PG&E is the only local utility that offers *rate-ready billing* service, whereby PG&E will calculate individual customer bills using the rates provided by the CCA. However, PG&E's rate-ready billing service offers fewer rate classes than its own billing services; therefore, cost comparisons may not be possible for CCA customers. PG&E also offers *bill-ready* billing service whereby the CCA calculates the amounts due from each customer and submits these amounts to PG&E for collections. SCE and SDG&E offer *only* bill-ready billing.

The CCA must also be able to obtain customer meter data and process this data for submission to the California ISO through its scheduling coordinator. This data is used by the California ISO to complete its financial settlement process. Customer meter data must be processed in accordance with the CPUC's protocols.

The IOUs will perform this function for CCAs as part of their metering service. However, the CCA must then apply load profiles to the usage data of customers whose consumption is measured on a cumulative monthly basis (e.g., residential and small commercial) in order to create hourly usage data to submit to the California ISO.

2.4.4. Administration

Administration and management of the CCA program includes finance, legal, regulatory, contract management, and other program management functions. The scope of necessary administrative functions depends on the complexity of the CCA implementation, which could range from the execution of a single contract with an energy services provider for operation of the entire program to full-scale planning and staffing required for comprehensive, in-house operation and management of the CCA program. There are other variations of program implementation that exist between these two extremes. At a minimum, a senior level manager with experience in the electric utility industry should head the CCA program.

2.5. Deciding Community Procurement Objectives

Local governments investigating CCA have many objectives to consider. They range from reducing costs for all customers (or for a specific customer class) to increasing the amount of renewable energy their communities consume. Making these decisions should be a public process that ensures the values of the community (ies) are reflected in the CCA program.

The following outline provides a planning template for a CCA resource portfolio. The questions posed in this outline will help a potential CCA determine how much and what kind of generation resources it ought to procure or own.

1. Renewable Energy Targets
    a. What percent of your community's electricity consumption do you ultimately want to serve through renewable resources? This amount may range between 20% (minimum required by 2010) and 100% (maximum possible).
    b. How quickly would you like, or are you able, to meet the target percentages determined in 1.a.? As a guideline, your plan should provide annual target percentages that achieve at least 20% by 2010.
    c. How do you want to procure renewable energy?
        1) Do you want to own (or invest in) renewable generation facilities? If so, what percentage of your renewable portfolio do you want to establish through community-owned assets? When can these facilities be brought on-line? How many megawatts (MWs) will they total? What capacity reserve will you need based on the type of generation you propose to own (wind and solar energy are intermittent resources and will require dispatchable resources that are available when they are not—this is called capacity reserve).
        2) What percentage of renewable energy will you purchase from the market? What are the contract dates and capacities (MW)?
2. Conventional Generating Resources (non-renewables)
    a. Do you want to own (or invest in) conventional generation facilities? If so, what percentage of your portfolio do you want to establish through community-owned, conventional generation assets? When can these facilities be brought on-line? How many MWs will they total?

b. What percentage of your portfolio will be established through purchases of conventional generation from the market? What are the contract dates and capacities (MW)?

3. Distributed Generation (local, non-centralized power generation, e.g., rooftop photovoltaic (PV) systems)

   a. What resources currently exist within the community? For each technology (PV, micro turbine, etc.) determine the following characteristics:

      1) Capacity (kW)
      2) Energy (kWh)
      3) Cost
      4) In-Service Dates

   b. What distributed generating resources may be potentially developed within the community? For each technology (PV, micro turbine, etc.) determine the following characteristics:

      1) Capacity (kW)
      2) Energy (kWh)
      3) Cost
      4) In-Service Dates

4. Spot Market Purchases—how much energy do you plan to buy on the spot market? (under 15% of the community's total energy portfolio is recommended)

5. Supply Portfolio Sensitivities—the future is unknowable. It is best to provide a range of possibilities for certain variables in your feasibility calculation so that you are aware of the best case/worst case possibilities. Possible variables for sensitivity analysis:

   a. Natural gas/power prices (+/- 25%)
   b. CRS (+/- 25%)
   c. IOU rate projections (+/- 5%)
   d. IOU rate design (General Rate Case proposals)
   e. Renewable subsidies (Supplemental Energy Payments [Energy Commission], Production Tax Credits [U.S.])
   f. Combined operation with other communities (Joint Power Authority)

2.6. Getting the Necessary Data

Local governments can request data on electrical consumption for all electric customers within a potential CCA's jurisdiction from the local IOU. A city or county requesting such data must include a statement from its mayor or county administrator that it is investigating, pursuing, or implementing community choice aggregation.

Certain aggregated information is available free of charge, while other customer information requires payment of modest fees and execution of a non-disclosure agreement to protect customer confidential data. Sample data request letters are attached in Appendix A.

Understanding each IOU's revenue requirement is also critical when determining the feasibility of a CCA program. The IOU's revenue requirement is the basis for establishing its rates, the key comparison for determining financial viability of a CCA.

Most of the data required to estimate an IOU's revenue requirement should be readily available in its General Rate Case, the current FERC Form 1 filing for each IOU, and in recent Cost of Service Proceedings with the CPUC. The data included in these publications/documents can then be projected forward to evaluate future years of CCA operations. These data can be found on the utility websites (www.pge.com, www.sce.com, www.sdge.com) in the regulatory information and financial sections.

2.7. Evaluating the Data

2.7.1. Study Approach

A financial analysis should be performed in order to develop statements of income for the CCA program. The calculated savings, or potential income, is the difference between the IOU's retail power costs and the CCA's projected cost of providing power.

IOUs provide services at regulated cost-based rates. Hence, the IOU's rates are directly tied to a demonstrated revenue requirement, which it is authorized by the CPUC to recover through rates. An IOU's revenue requirement includes the utility's expenses, return or profit, and taxes paid by the utility.

To determine potential savings or income, a financial analysis should compare the IOU's revenue requirement at current and projected rates with the revenue requirement of the CCA program. If more than one CCA supply portfolio is studied (for example, varying percentages of renewable resources), each should be compared to the IOU to determine if it will produce cost savings or benefits.

A CCA program is limited to providing the electric commodity only. The IOU will continue to provide electric delivery services over its existing distribution system and will provide end-consumer metering, billing, collection, and all traditional retail customer services (i.e., call centers, outage restoration, extension of new service). Therefore, to evaluate the potential benefits of CCA, only costs associated with wholesale electric commodity procurement and related business expenses need be considered.

In preparing the financial evaluation for a CCA program, a community should perform a thorough analysis of:

- The IOU's forecasted rates (including CRS).

- CCA energy or commodity costs (including generation ownership, power purchase contracts, renewable energy contracts, and spot-market purchases).
- California ISO charges.
- Operations and scheduling costs.
- Financing costs.
- Revenue offsets and available financial incentives.

Each of these items should be factored into the analysis. The CCA program's capital costs should be amortized over a 30-year period and financed at a municipal rate (presently 5.5%). Related interest and amortization should be included in the annual costs of the program.

The object of the financial analysis is to compare the total costs of operating the CCA program with the total costs of continuing to take retail utility service. The results of this financial analysis should be incorporated in the potential CCA's feasibility analysis.

2.7.2. Customer Base

The potential customer base for the CCA program includes all of the electric customers in the community. However, customers have the option to opt out of the CCA program and continue to receive their electric service from the IOU. Some customers may choose to not participate in the program, or opt out during the initial 60-day free opt-out period, and some direct access customers may be prevented from joining the program until their direct access contracts expire.

The number of customer opt outs will depend on various factors, not the least of which is how the CCA's electric rates compare to those of the IOU. Other factors that will influence customers' opt-out decisions include whether the CCA provides non-price benefits important to customers, such as increased renewable energy purchases or expanded energy efficiency programs, and customer loyalty or enmity to the IOU. Many of these factors are directly dependent on details within the CCA's implementation plan, and the impacts cannot be reasonably estimated prior to completion of the CCA's implementation planning process.

For feasibility analysis development, 100% customer participation can be used as a starting point. Within a reasonable range of assumed opt-out percentages, the study results can be adjusted proportionately. The CPUC has chosen 5% for residential customers and 20% for commercial/industrial customers as default opt out figures for planning purposes.

2.7.3. Key Assumptions

This section describes the high level assumptions that provide the framework for a feasibility analysis. The detailed assumptions used in the Energy Commission-sponsored pilot program are listed in Appendix B.

- CCAs must maintain adequate capacity reserves to maintain reliability standards and will follow standard industry risk management practices. They will be held to the same capacity reserve standard as the IOUs.
- CCAs will match or exceed the renewable energy content of the IOUs' portfolios and are eligible for the existing Energy Commission subsidies provided for renewable energy procurement up to the minimum RPS (i.e., subsidies are available for the first 20% of renewable energy).
- Market prices for renewable energy will reflect the developer's costs, including the effects of available subsidies.
- CCAs will be able to finance generation projects.
- CCAs will be able to obtain electricity from the wholesale market on comparable terms with the IOUs.
- The CPUC will not allow IOUs to negotiate special rates or contracts to retain customers.
- CCA operations will be able to be outsourced to third parties.
- Reinstatement of direct access will not preempt CCA rights and customer relationships.

2.7.4. Utility Rate Benchmarks

Estimates of CCA cost savings should be assessed by comparing CCA costs to the rates that would otherwise be charged by the IOU. The IOU's rates are derived from its costs or revenue requirement. When developing the feasibility analysis, the feasibility contractor will have to make some assumptions about future IOU rates. These assumptions should be clearly delineated within the feasibility analysis.

2.7.5. Cost Responsibility Surcharges

The single greatest obstacle to achieving significant cost savings through CCA in the next several years is the imposition of cost responsibility surcharges (CRS) on CCA customers. The CRS is designed to shield the IOU's remaining customers from any cost increases that might result from customers switching to CCA service.

The feasibility contractor should model expected CRS using the methodology adopted in CPUC Decision (D.07-01-025). According to this method, the above-market portion of the IOU's generation portfolio, including IOU contracts and resources and the DWR contracts, are included in the CRS. Other elements of the CRS include the DWR bond charge and, for PG&E only, the charge for recovery of the regulatory asset that was established to enable PG&E's emergence from bankruptcy. The latter two costs are reasonably certain and predictable, while the uneconomic portfolio costs are less easily predicted because they depend on future electricity market prices and the IOU's future generation costs.

There is an inverse relationship between the CRS and wholesale electricity market prices. If future power prices decline, the CRS will be higher, but the cost of procuring power for the CCA program will be lower. These two impacts tend to offset one another. Therefore, the magnitude of the CRS should not be looked at in isolation, but should be assessed in context with market price assumptions used in the overall feasibility assessment. The net effect of higher or lower power prices on the overall cost of service for the CCA program should be modeled in a sensitivity analysis.

2.7.6. Renewable Energy Subsidies

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

- Production tax credits
- Renewable Energy Production Incentives
- Supplemental Energy Payments (Public Goods Funds)

Some of the incentives, such as the production tax credit for renewable energy production, are short-term and must be reauthorized by Congress on an annual basis. Others, such as the public goods funding for renewable energy development administered by the Energy Commission (Supplemental Energy Payments), are more long-lived, but are contingent on the amount of public goods funds collected through utility rates. A community studying CCA feasibility will need to decide which of these subsidies to include in its analysis.

The additional costs for purchases of renewable energy up to the minimum RPS should be offset by Supplemental Energy Payments for renewable contracts, while the incremental renewable energy above and beyond the minimum requirement should be assumed to receive no subsidy. Thus, in financial analyses of the costs of renewable energy, anything above the first 20% should be paid entirely by customers of the CCA.

It should also be assumed that Supplemental Energy Payments will not be available to offset costs of renewable resources that CCAs own or otherwise finance. The reason for this assumption is that the process for determining Supplemental Energy Payments is premised on the utilities conducting competitive solicitations for long-term supply contracts with producers of renewable energy. Funds are made available to winning bidders to cover their costs above a market benchmark, determined by the CPUC.

2.7.7. Financial Analysis Structure

CCA customer electric loads should be applied to the IOU's current and projected generation rates to yield its revenue requirement from the customers in the potential CCA area. All CCA operating expenses should be projected and subtracted from the IOU's revenue requirement to yield the projected financial benefit. Elements that should be contained in the analysis are summarized below.

- Utility Forecast Generation Rates
    - Utility retained generation (IOU-owned power plants)

    - Qualifying facility generation (higher priced generation contracts)
    - Bilateral power purchase contracts
    - New renewable energy purchases
    - California ISO charges
    - Residual spot market purchases or sales
- CCA Energy Cost (Commodity Costs)
    - Spot market purchases
    - Power purchase contracts
    - Renewable energy contracts
    - Generation ownership
- California ISO Charges
    - Ancillary services/reserves
    - Grid management charges
    - Deviation charges
- Operation and Scheduling Costs
    - Electricity procurement
    - Risk and credit management[2]
    - Load forecasting
    - Scheduling and settlements
    - Rates
    - Account services
    - Administration
- Non-Bypassable Charges/Cost Responsibility Surcharge
    - Uneconomic utility retained generation and power contracts
    - DWR power purchase contracts
    - DWR bond charges—Financing past purchases

2.7.8. Load Analysis

Detailed definition of community electric power needs is required to determine the economic viability of the CCA. Community electric demand and energy consumption,

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2. The costs of uncollectible customer accounts are not explicitly included in the pro forma, under the premise that the CCA would require customer deposits from customers that pose likely credit risks, similar to the accepted utility practice. Under current rules the CCA cannot cause service to be shut off to the customers for failure to pay its portion of the bill, whereas the utility can; however, the CCA has the right to return the customer to the utility for failure to pays its charges.

generally referred to as electric load, should be analyzed, beginning with and based upon data provided by the IOUs in response to the communities' formal requests (see Appendix A for sample data request letters). The communities' annual hourly load shapes should be developed and a determination made regarding associated energy supply requirements.

Each utility publishes annual load shapes for the major customer classes, which can be used in conjunction with the monthly energy consumption data by rate class, provided in response to the CCA's data request, to model the CCA's overall load shape. The time-of-use supply requirements serve to define the types of resources necessary to supply electric energy to the CCA. Section 2.4.1, Portfolio Operations, provides additional discussion regarding time-of-use considerations, load forecasting, and resource selection with respect to selection of community power supply.

2.7.9. Load Forecast Method

Community electric load data should be provided by the IOU and include at least 12-month, year-to-date energy consumption and the number of customers by rate class. Data for residential customers should include the percentage of residential consumption that occurs in each of the tiers consistent with the tiered rate structure the IOU has in place. The IOU may provide more rate classes than needed, which can be collapsed into seven higher-level Customer Sectors. Suggested rate classes and their generic sector rate class description assignments are listed in the following Table 2-2.:

Table 2-2.

Rate Schedule to Customer Sector Assignment

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

Monthly load information should be ordered by month, January through December, to reflect monthly seasonal use patterns and should be treated as prototypical for a particular year's energy consumption. Static load profiles, as published by the IOU, can be used to allocate monthly energy (kWh) into each hour of the month and then to each of the 8,760 hours within a year.

Rate class static load profiles, which can also be developed from available data (based on descriptions provided in the previous table), should be characteristic of load usage patterns within each of the Customer Sectors. The following Table 2-3. reflects an example:

Table 2-3.

Static Load Profile Assignment

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

As part of a prospective CCA's load analysis, it is recommended that a 20-year electric load forecast be performed. Electric energy requirements and customer populations should be escalated based upon the most reliable sector-specific growth planning statistics. If the community does not have this information available, the IOU system-wide growth rates can be applied.

An example of the number of customer accounts and annual energy sales for the initial year (2006) of a program are shown in Table 2-4. below.

Table 2-4. Forecast number of accounts and annual energy sales

	2004 *		2005 *		2006 *	
	Accounts	kWh	Accounts	kWh	Accounts	kWh
Residential	46,278	186,558,920	46,426	187,155,909	46,574	187,754,808
Small Commercial	4,476	93,709,959	4,550	95,256,173	4,625	96,827,900
Medium Commercial	542	96,730,076	551	98,326,122	560	99,948,503
Large Commercial	56	52,193,719	57	53,054,916	58	53,930,322
Large C/I	7	79,828,758	7	81,145,932	7	82,484,840
Street Lighting	22	4,671,795	22	4,671,795	22	4,671,795
Traffic Control	144	668,871	144	668,871	144	668,871
Total	51,524	514,362,098	51,756	520,279,718	51,989	526,287,039

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

Growth Rates

Residential	0.32%
Commercial	1.65%
Street Lighting and Traffic Control	0.00%

2.7.10. *Community Energy Load Shape*

The community composite annual energy load shape (average kW per hour) can be developed by combining average loads in each hour from each of the Customer Sector load profiles identified above. A prototypical annual load profile is shown in Figure 2-2.

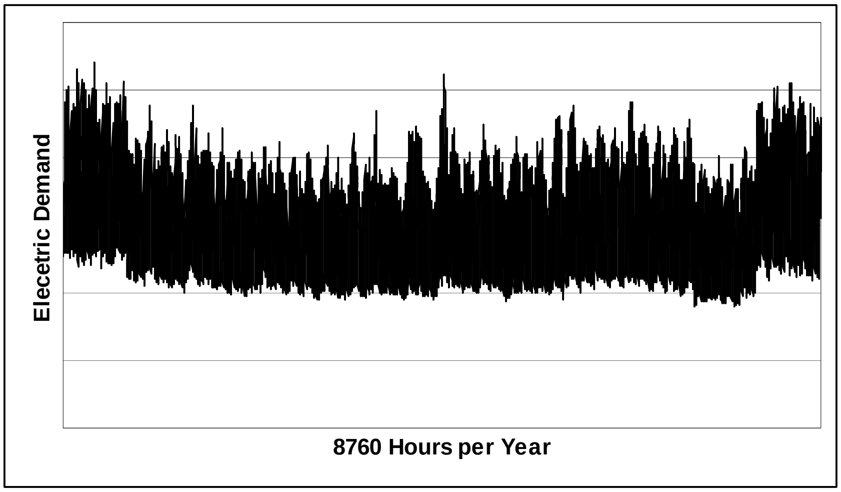

Figure 2-2. Prototypical annual load profile

Source: Navigant Consulting, Inc.

Electric load should then be broken down into quarterly and weekly demand periods to capture seasonal variation in projected loads and electric generation resource requirements. The resulting quarterly minimum, as well as peak power requirements, will be the basis for sizing the portfolio of contracts and generation resources needed to serve the community's (ies') load profile.

2.7.11. *Renewables Portfolio Standard Requirements*

The California Renewables Portfolio Standard Program (RPS) established by Senate Bill SB 1078 (Sher, Chapter 516, Statutes of 2002), requires that a retail seller of electricity provide a specified minimum percentage of electricity generated by qualifying renewable energy resources. CCAs will be retail sellers of electricity and, therefore, subject to this law.

Each IOU is required to increase its total procurement of eligible energy resources by at least 1% per year so that 20% of its retail sales are procured from eligible renewable energy resources by 2010. Aggregated loads of a CCA program are a subset of the load currently served by the IOUs. Therefore, analyses can assume that renewable energy requirements of a prospective CCA will, at a minimum, be equal to the renewable energy percentage required of each IOU.

The bill requires the CPUC to adopt rules for implementing the RPS (CPUC Rulemaking 06-05-027), and CCA planners must understand these renewable energy requirements before they can assess the cost-benefits and make decisions to implement a CCA program.

2.7.12. Supply Portfolio Details

A CCA program should be supplied from a diverse portfolio of energy resources. The portfolio should be designed to achieve the CCA's renewable energy objective in stages. The CCA may need to initially match the renewable content of an IOU's portfolio and then incrementally increase the renewable component to achieve its goal (at least 20%) by 2010. The CCA can invest in generation resources to meet its energy requirements, especially for base load amounts (the minimum amount used every day). Typically, the portfolio should also include power purchases through long-term (five-year) contracts and spot market purchases to supplement the CCA's generation resources.

The resource types may include:

- Spot market purchases—short-term electricity purchases to supplement supplies under contract or ownership control of the CCA.
- Contract purchases—longer-term, fixed-price power purchases. Terms can be monthly, quarterly, annual, or multi-year.
- Natural gas power production—production from a combined cycle natural gas combustion turbine owned by the CCA used for base load or shaping purposes.
- Renewable energy purchases—purchases of renewable energy to meet the CCA's renewable resource goals, with a minimum equal to the IOU's renewable energy mix.
- Renewable energy power production—production from renewable energy resources owned by the CCA.
- Off-system sales—sales of excess energy into the spot market at times when the resources under contract or ownership are above the CCA's load requirements.

The resource mix can include both conventional and renewable resource ownership. The initial portfolio will likely contain only purchases from the open market and will later add production from wind, geothermal, and other renewable resources. The earliest feasible date for a CCA to acquire equity in a new generation resources, considering lead times for negotiations, permitting and financing, will be several years.

2.7.13. Alternative Supply Scenarios

Analyzing alternative supply scenarios will assist a potential CCA in understanding the cost effectiveness and tradeoffs among different resources that could be included in a CCA's supply portfolio. For the Energy Commission-financed pilot study, analyses were prepared for four supply portfolios that differed by the amount of renewable energy included in the portfolio and by whether the CCA owned generation resources used to supply electricity to the program. The four alternatives were:

Alternative Supply Scenario 1

Supply Scenario 1 assumed the CCA will double the renewable content of the IOU (40% v. 20%) and purchase all of its load requirements from the open market. Including renewable energy increased the portfolio's cost, even after considering the subsidies potentially available to the CCA's renewable energy suppliers.

The renewable energy costs for purchases up to the minimum required by the RPS (20%) were assumed to be offset by Supplemental Energy Payments administered by the Energy Commission, while the incremental renewable energy above and beyond the minimum requirement was assumed to receive no subsidy. Thus, the second 20% of targeted renewable energy was paid entirely by customers of the CCA.

Capital expenditures associated with Scenario 1 were limited to program startup costs. This supply strategy usually resulted in a loss over the 20-year study period.

Alternative Supply Scenario 2

Supply Scenario 2 assumed the CCA will match the renewable content of the IOU (20%) and purchase all of its load requirements in the open market. Renewable energy subsidies were available to offset the incremental cost of the CCA's renewable energy purchases.

Capital expenditures of Scenario 2 were limited to program startup costs. This strategy resulted in a smaller loss over the study period than Scenario 1.

Alternative Supply Scenario 3

Supply Scenario 3 assumed the CCA will double the renewable content of the IOU (40% v. 20%) and produce electricity from resources that it owns. The portfolio also included power purchases through five-year contracts and spot market purchases to supplement the CCA's own electricity production. Supply Scenario 3 included both conventional and renewable resource ownership.

The portfolio initially contained only market purchases similar to Supply Scenario 1, but after three years, it included production from wind and natural gas-fired, combined-cycle resources. The third year was selected as the earliest feasible date for the CCA to acquire equity in a new generation resources, considering lead times for negotiations, permitting, and financing.

No subsidies were assumed to be available to offset costs of the CCA's renewable resources. Subsidies were included for renewable energy purchases, if needed, consistent with the subsidy described for Scenario 1.

Capital expenditures for Scenario 3 included startup costs and generation investments over $100 million. This supply strategy usually resulted in total savings over the 20-year study period.

Alternative Supply Scenario 4

Scenario 4 was similar to Scenario 3 except that the portfolio matched the renewable content of the IOU's supply portfolio (20%) with a corresponding increase in the capacity of natural gas fired generation financed by the CCA. Capital expenditures associated with Scenario 4 included startup costs and generation investments of less than $100 million.

This supply strategy resulted in total savings over the study period slightly smaller than Scenario 3.

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

The results of the pilot program studies are specific to the communities studied. Not all had the same savings or losses, although the trends were consistent in all instances. That is, the difference in cost between 20% and 40% renewables was minor, and CCA financing of generation was required to capture significant savings.

This example is meant to demonstrate that a potential CCA should model various supply and financing scenarios in its planning process. Each CCA may have other alternatives to test.

2.7.14. Sensitivities

Sensitivity analyses can help put upper and lower bounds on expected financial results from implementing a CCA program. Sensitivity analyses for the major variables expected to impact the financial results should be run. The pilot project analyzed the following sensitivities:

- Natural gas and power prices (+/- 25%).
- CRS (+/- 50%).
- IOU system average rate projections (1% to 3% annual growth).
- IOU revenue allocation changes to reduce cross subsidies.

None of the sensitivity scenarios eliminated program savings over the study period. However, the high natural gas/power price scenario and the high CRS scenario caused revenue losses in the early years of the program.

A CCA should pay particular attention to changes in these variables if and when it proceeds with implementation of its CCA program. A phase in of program operations, as described in Section 1.11, could lessen exposure to these factors by allowing initial program operations to benefit from the collection of higher margin rates from commercial customers, which would help offset potential financial risks of this nature.

Another method for accelerating financial benefits would be to create a rate stabilization fund by issuing debt that would be backed by the future revenue streams of the program, thereby moving a portion of future savings forward in time.

2.7.15. Cost of Renewable Energy

The Energy Commission's *Renewable Resources Development Report* (RRDR) published in November 2003 shows the mix and costs of the renewable resources that will likely be utilized to meet the California RPS. The cost of buying renewable energy can be estimated by creating a generic portfolio of these resources using the types of generation projected in the RRDR study to calculate a weighted average cost. The average cost of these resources, weighted by their expected contribution to the RPS is shown in Table 2-5 below:

Table 2-5. Renewable resource technologies expected to fulfill the California Renewables Portfolio Standard (2003 Dollars)

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

Source: California Energy Commission *Renewable Development Resource Report*

* The cost of wind is based on the levelized cost of $49 per MWh presented in the RRDR plus an additional $11 per MWh capacity cost to reflect that capacity must be acquired separately because wind resources are intermittent. These figures do not include production tax credits, which were scheduled to expire at the end of 2007.

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

All else being equal, and assuming no CCA capital financing of renewable energy, the cost of doubling PG&E's 14% renewable mix would be $18/MWh * 0.14 = $2.52 per MWh. In this case, a typical household would pay $1.26 more per month to double the amount of renewable energy used to supply its electricity consumption.[3] The premium declines over time as natural gas and electricity market prices are expected to rise faster

3. Typical residential consumption is approximately 500 kWh or 0.5 MWh per month.

than the cost of renewable energy production. By 2018, the market price of renewable energy is expected to be no greater than the cost of conventional generation resources.[4]

The projected costs of renewable and conventional electricity that were used in the 2005 feasibility studies are shown in Fig 2.3 below[5]:

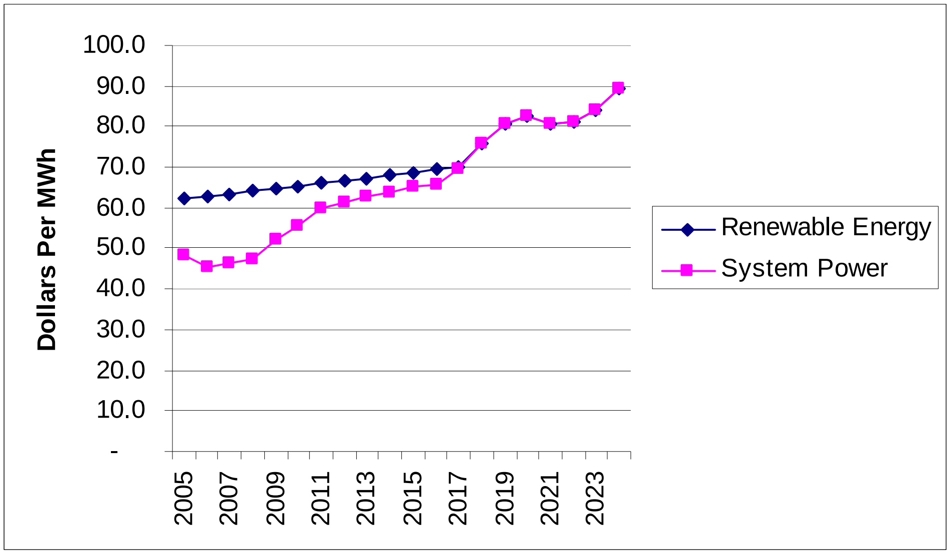

Fig 2-3. Northern California market price projections for renewable and conventional electricity

Source: Navigant Consulting, Inc.

2.7.16. Municipal Financing of Renewable Energy Development

A CCA can reduce the cost of acquiring renewable energy by financing development of the renewable resources used to supply its program. The following Table 2-6 compares the total cost of a hypothetical 100 MW wind energy project using the financing structures that are typically available to an IOU vs. those available to a CCA.

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

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

5. It should be noted that the costs of renewable and non-renewable electricity have increased since the time of the study; however, the renewable cost premium is still about the same.

Table 2-6. Cost comparison—IOU vs. CCA ownership of a 100 MW wind resource (Thousand of Dollars)[6]

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

Source: Navigant Consulting, Inc.

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

2.7.17. Operational Issues for Renewable Energy

Renewable resources are generally non-dispatchable, which means they cannot be turned on or off at will. Instead, they can operate as either base load resources or on an as-available basis. Wind and solar resources produce electricity only during certain times of the day when there is sufficient wind or sun. This places an operational limit on the amount of renewable energy that can be included in the overall resource mix.

Depending on a community's load duration curve, which defines its base load requirements, the operational limit could range between 50% and 70%.[7] It would be possible to exceed these amounts by over-procuring, but that would require the CCA to sell excess energy into the market during many hours of the year.

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

One way that a CCA could safely exceed the operational limits on renewable energy is by purchasing renewable energy certificates (RECs) from producers of renewable energy. The Energy Commission is currently investigating a system that would facilitate trading of RECs, and private markets for RECs have been in existence for several years.

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6. Tax incentives for renewable resource development, such as accelerated depreciation and production tax credits, can reduce the cost advantage of the CCA to about 15%.

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

The tradable REC concept allows the renewable attribute associated with renewable energy production to be sold separately from the electrical energy. Through appropriate tracking and verification, the buyer can be assured that for each REC purchased, a kWh of renewable energy was produced during the year. However, the renewable production need not match the buyer's load requirements on an hour-by-hour basis.

By separating the renewable attribute from the electrical energy, a CCA could ensure that enough renewable energy was produced over the course of the year to supply 100% of its customers' load requirements, while avoiding the need to sell excess energy. The price of the REC should be approximately equal to the cost difference between the market price for system power and the cost of renewable energy production, after considering all available incentives.

2.8. To Build or Not to Build?

There are essentially two strategies for a CCA to obtain the necessary electricity to serve its customer base: By contracting with energy suppliers, and through ownership of power generating plants (asset ownership). Under the contracting strategy, the CCA provider would go to the competitive wholesale electricity market and would have numerous suppliers provide competitive bids to meet the energy requirements of the CCA. Under the asset ownership strategy, the CCA provider would meet all or a portion of its electricity requirement through the ownership of generation assets.

The Energy Commission pilot study found that to beat IOU rates, CCA ownership of at least some of its generation supply is necessary. Simply buying from the market will at best match IOU pricing (since the CRS will be added to the market price to equal the IOU's portfolio average). CCA administrative costs will also need to be covered, which would result in a greater cost to CCA customers than to similar customers of an IOU.

A CCA pursuing ownership of power generation resources should finance the project with tax-exempt bonds that provide a cheaper rate of capital than that which is available to an IOU. The bonds will be backed by the ability of the CCA to collect revenues from its customers' utility bills and from other power sales agreements entered into by the CCA provider.

Ultimately, alternative operating scenarios contemplated in the Energy Commission-funded pilot study demonstrate that resource ownership is critical to the long-term financial viability of a CCA. Therefore, a CCA implementation strategy should strongly consider options involving generation ownership/development.

2.8.1. Financial Projections

The total cost of service for the CCA program should be calculated and compared to the generation costs charged by the IOU. The differences represent potential savings or costs associated with the CCA program. Any savings should be shown for each year in the study period, with positive numbers indicating lower costs for the CCA and negative numbers indicating higher costs. Costs or savings should be shown both in dollars per year and as a percentage of customers' monthly electric bills.[8] The following Table 2-7 provides a sample summary of cost savings from CCA.

Table 2-7. Sample summary of electric cost savings from community choice aggregation (Millions of Dollars)

Year	Total CCA Costs	PG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	-	0%
2006	41.3	42.8	1.4	2%
2007	41.4	43.4	2.0	3%
2008	43.6	44.9	1.3	2%
2009	42.1	45.9	3.8	5%
2010	44.4	48.1	3.7	5%
2011	45.8	49.5	3.7	4%
2012	47.0	51.1	4.1	5%
2013	43.0	48.4	5.3	6%
2014	43.9	49.7	5.7	7%
2015	46.6	51.3	4.7	5%
2016	47.5	52.4	4.9	5%
2017	49.2	54.9	5.7	6%
2018	51.9	58.8	6.9	7%
2019	54.3	62.3	8.0	8%
2020	57.4	64.3	6.9	6%
2021	58.0	64.7	6.8	6%
2022	59.0	66.1	7.1	6%
2023	58.2	66.3	8.0	7%
2024	61.0	70.1	9.1	8%
Total	935.7	1,035.0	99.3	6%

Source: Navigant Consulting, Inc.

In this case, the total nominal savings over the study period are $99.3 million or approximately 6% of customers' total electricity costs. Cost savings average approximately $5.2 million per year.

2.9. Sample Feasibility Study

The city of Berkeley has posted the feasibility study completed for it by the Energy Commission-funded pilot program on its website. It can be viewed at: http://www.ci.berkeley.ca.us/sustainable/government/CommunityChoice/CCA.html

8. The percentage savings are expressed based on total electric bills, including IOU delivery charges. The percentage savings on the generation component of bills would be approximately double the percentages shown.

3.0 Developing a Community Choice Aggregation Implementation Plan

3.1. Section Summary

Once the decision has been made to establish a CCA program, an Implementation Plan (IP) must be filed with the CPUC. This section discusses the necessary requirements for developing an IP.

Any local government wishing to establish a CCA program needs to fully inform its residents, businesses, institutions, and municipal departments of its interests and intentions. This informational campaign should start very early in the investigative process in order to secure stakeholder buy-in.

Before developing an IP, a community must make several fundamental decisions. One key decision is whether the community should act independently and develop a CCA for its own jurisdiction alone, or whether the community should reach out to other jurisdictions, forming a joint CCA. The city or county will need to determine whether the economies of scale are worth sharing decision-making control with other communities.

Another key choice will be operational structure. How will the duties described in Section 2.4 be accomplished? Will they be outsourced or will the CCA develop its own operations center and administrative staff? If out-sourced, the CCA will need to choose an operator or operators that will be identified in the IP.

The CCA will have to include the source of its electricity in the IP. Therefore, it will need to get quotes from suppliers and be ready to sign contracts with them in time to commence serving its customers on an agreed-upon date.

Phasing in operations is allowed. Phasing may help a CCA work out operational glitches before having to provide service for the entire community. It may also be a way to eliminate potential cash flow problems in the early years of implementation. If a phased program is planned, it must be described in the IP.

Filing an IP initiates actions on the part of the CCA, the CPUC, and the utility. The CPUC will set the CRS and the earliest possible date for CCA service to commence. The CPUC may ask the CCA for more information in order to determine the CRS for its customers. The CCA must inform its potential customers of their right to opt out of the CCA program (four notices are required: two before customers are switched over to CCA service, and two after). The CCA must register with the CPUC and post a bond or other security to cover the cost of program default. Once notified that the CCA program will begin, the utility must transfer all CCA accounts to the new supplier within a 30-day period that coincides with its monthly billing process.

3.2. Implementation Plan and Statement of Intent Requirements

AB 117 lists the requirements of an implementation plan that must be filed with the CPUC. Following submittal, the CPUC will use the IP to determine the CCA's customers' CRS. The IP must be adopted at a duly noticed public meeting of the city, county, or cities and counties forming the CCA.

The IP must include the following elements:

- Program structure, organization, operations, and funding.
- A system for ratesetting.
- Provisions for disclosure in setting rates and allocating costs among participants.
- Methods for entering and terminating agreements with other entities.
- Rights and responsibilities of program participants (consumer protection, credit requirements, and shutoff procedures).
- A description of third-party suppliers (including financial, technical, and operational capabilities).

The IP must also be accompanied by a statement of intent, which discusses how the CCA will address:

- Universal access.
- Reliability.
- Customer class equity.
- Other requirements established by state law or the CPUC.

The San Joaquin Valley Power Authority's implementation plan can be viewed at:

http://www.communitychoice.info/sjvpa/documents.php

3.3. Deciding Whether to Join With Other Communities

Some communities are considering establishing their own CCA. The city and county of San Francisco, which owns and operates a municipal water and power utility, is one example. However, other local governments are investigating CCA with neighboring communities in order to achieve improved financial results through a joint powers agency (JPA).

By forming a JPA and jointly implementing a single CCA program, local governments will increase administrative efficiency of the program and should experience cost savings through economies of scale. Program implementation by individual communities will require higher investments of time and financial resources (in terms of cost/kWh), including ongoing operations costs. Collaborative programs also reduce potential risks for each participating city or county, as all participants share the program's risk.

The primary disadvantage of a JPA is the reduced autonomy for each participating community. JPAs also involve another layer in the decision-making process, which may be made more difficult by potentially dissimilar interests of elected officials from multiple jurisdictions.

3.3.1. Economies of Scale From Combined CCA Operations

By combining the electric loads of multiple cities and/or counties, a CCA should be able to achieve economies of scale, reducing administrative and operational costs to individual members. Variations in community load shapes enable sharing capacity reserves, a savings in total procurement costs. In addition, the load shape of a joint CCA program should tend to be more statistically *normal* (when compared to the load shape of a single community, which would comprise a much smaller statistical sample size and would reflect the peculiarities of an individual community's load profile), which will allow the CCA to procure a larger amount of standard, base load energy products (base load products generally reflect lower pricing when compared to peaking or dispatchable products).

In general, joint CCA implementation should reduce cost per kWh, resulting in lower electric rates for CCA customers. Furthermore, a larger organization, such as a JPA-based CCA program, would wield greater political influence in the regulatory process, which may result in additional, short- and long-term benefits for the CCA.

The Energy Commission-funded pilot project included a financial assessment that combined seven Bay Area communities in a common CCA operation. This joint operation yielded over $300 million (34%) in additional financial benefits during the first 20 years compared to individual CCA operations.

Joint Powers Agency Structure Option

Only cities, counties, or groups of cities and counties are permitted to be CCAs. JPAs are common legal structures that many public agencies have formed to offer services in a more economical and efficient manner. CCA implementation involving JPA formation can combine city and county jurisdictions to secure long-term power contracts or to develop JPA-owned generating resources. Joint CCAs may benefit from flatter electric load shapes, which reduce the overall cost of service.

The following describes some of the possible benefits and impediments of the CCA-JPA organizational structure:

Benefits:

- The JPA structure will enable its members to jointly exercise common powers.
- The CCA-JPA organization will be a public, nonprofit agency.
- Parties to the JPA will share costs/risks and assist with all JPA projects.

- JPA formation will allow members to aggregate financial resources when securing long-term power contracts or entering into agreements to develop power plants.
- JPA members will benefit from economies of scale when developing generating resources, as larger generating projects may offer greater operating efficiencies and lower cost per kWh.
- The JPA will be able to issue low-cost bonds by ordinance subject to referendum but without a vote of the elected officials within the JPA communities.
- The JPA will minimize exposure of its members to risk while providing access to capital, political, and intellectual resources of the other JPA members.
- The JPA will reduce or eliminate the need for duplicate staffing and supporting systems that facilitate energy procurement/supply for its membership.

Impediments:

- Forming a JPA will be time consuming; all parties must agree on the approach and structure (the fewer the parties, the more streamlined the process).
- Providing equitable representation for both large and small members without compromising either's options/interests will be a challenge.
- The decision-making process will be cumbersome, during both formation and operation (decisions tend to be *consensus*-driven, slowing processes and compromising positions as members seek to protect their own interests).
- A JPA may result in less control over ratesetting decisions.

Structural Options for a JPA

If a group of cities and counties decides to form a CCA JPA, there are several options to consider. Three possibilities follow.

Option 1: Single CCA "JPA" Option

Under the single CCA option, the JPA governing board would have primary responsibility for managing all aspects of a common CCA program. The JPA would establish itself as a CCA, and the member cities/counties would authorize their participation in the JPA by resolution or ordinance. The JPA would have a direct relationship with CCA customers, the IOU, and energy suppliers. Common activities may include:

- Resource planning and supply solicitations
- Contract management (suppliers, other contractors)
- Project financing
- Regulatory tracking and participation
- Marketing
- Rate design

- Program terms and conditions development
- Finance and accounting
- Legal services

The member communities would influence decisions of the JPA governing board through designated representatives on the board according to the voting rights set forth in the JPA agreement.

Option 2: Multiple CCA "Association" Option

Under the Association option, each city or county would form its own CCA program. However, member local governments would engage in common activities related to their individual CCA programs, primarily the first three activities listed above. Other supporting activities related to regulatory support, marketing, etc., might also be performed on a joint basis. It is likely that a JPA would be formed to facilitate the joint activities that would underlie the individual CCA programs. The activities that could be jointly undertaken include:

- Resource planning and supply solicitations
- Contract management
- Project financing
- Regulatory tracking and participation (common)
- Marketing (common)
- Finance and accounting (common)
- Legal (common)

The members would individually administer the front-end or *customer-facing* aspects of their respective programs. Each community would also have responsibility for program finances and regulatory compliance. The activities undertaken by the individual cities and counties could include:

- Rate design
- Program terms and conditions
- Regulatory tracking and participation (CPUC registration, compliance reporting)
- Marketing
- Finance and accounting
- Legal

Comparing the two structures, local governments would have greater autonomy under the association model, but they would also have more responsibility and staffing requirements. IOU charges for supporting CCA implementation would increase because there would be multiple CCA entities rather than one. If rates differ among the cities, there would be greater costs related to administering more than one set of rates, different opt-out notices, and different program marketing materials.

Option 3: Single CCA With Member Rate-Setting Authority

There is also a third option that would combine elements of the two previously described organizational structures. This organizational structure would be similar to Option 1 in that there would be a single CCA entity, but members would have the ability to set unique rates that would be charged to customers within their respective jurisdictions. Each member would be responsible for collecting enough revenue in rates to cover its agreed-upon program costs. This approach would retain many of the cost savings advantages available to a single CCA program, while providing members with autonomy during ratemaking processes for their cities.

3.3.2. Cost/Benefit Allocation

Under any of these approaches, the JPA would determine its annual program budget or revenue requirement based on its projected costs of supply, IOU transaction fees, administration costs, financing costs, reserves, and other costs. The JPA would then perform a cost-of-service study to allocate costs to customer classes (residential, commercial, etc.).

If the JPA sets rates for all members (Option 1) then rates would be designed for each customer class based on cost-of-service and other considerations. Margins (profits) could be allocated to each member based on the unique margins derived from sales within each member's boundaries.

The ratemaking decisions of the JPA would impact profits retained by each member, as customer mixes may differ significantly within each member city or county. In effect, the JPA would be determining how much of the cost savings should flow through rates versus how much should be retained by JPA members.

For example, if the JPA established relatively low rates for residential customers and higher rates for commercial customers, cities or counties with larger proportions of residential customers would have less profit available to them. Under this approach, the JPA may need to incorporate bylaws that prevent establishing rates that would result in negative margins for any member local government.

Alternatively, if member cities will be independently setting rates for their customers (Options 2 or 3), then the JPA could allocate program costs to each member city or county, which would, in turn, need to be recovered through the rates established by each. The cost responsibility assigned to each member of the JPA would be based on the cost of service for each defined customer class as well as the volume of retail sales derived from specific customer classes within each member's jurisdiction. Each member would be responsible for setting its program rates at levels sufficient to recover its total cost responsibility to the JPA. Members would be free to design rates as they see fit, as long as these rates result in collections that cover the members' cost responsibility to the JPA.

The issues that need to be considered in selecting a rate-setting structure (whether the JPA sets the rates or its members do) are:

- The likelihood that consensus can be achieved among JPA members for an overall program rate structure, including decisions about how benefits should be allocated among customers/members.
- The preference to have rates established by the JPA, with a single focus on the CCA program, rather than by multiple local governments with potentially dissimilar goals/objectives.
- The willingness of member cities and counties to take on the extra burdens in the "Association" model (Option 2).
- The likelihood that the ratemaking authority provided in Option 3 will satisfy desires for local control and self-determination.
- The balance between the additional costs and complexity associated with maintaining multiple rate structures and the perceived or actual benefits conferred to each community by allowing unique service rates.

3.3.3. Revenue Bond Issuance

A JPA may issue revenue bonds by ordinance subject to a vote of its constituents but without a vote of the elected officials within the cities or counties comprising the JPA. JPAs may also issue securities by resolution of the JPA backed by loan agreements and/or bond purchase agreements with participating member agencies. The law provides that some, but not necessarily all, of the members of a JPA may participate in a bond issue and that only those participating will be obligated to repay the debt incurred.

For a list of financing alternatives to consider once a JPA has been formed, see Appendix C.

The financing method that is ultimately chosen by the CCA-JPA will be based on a number of factors:

- Purposes of Financing. Proceeds from financing can be used for a number of different purposes, including but not limited to:
    - Startup costs
    - Construction of new facilities and equipment
    - Initial capital for power purchases
    - Operations and maintenance expenses

  The purpose of financing can and will affect the type of bond issue that the CCA-JPA may utilize. In the end, the JPA may execute a series of financing transactions to meet each of its various purposes.

- Tax Eligibility. An important consideration in determining the appropriate financing technique required to fund specific transactions will depend largely on the tax-exempt eligibility of the potential financing. As all objectives (i.e., purposes and uses of the proceeds) of the financing become known, counsel for the JPA will be able to make a determination as to whether or not the JPA will be eligible to issue tax-exempt bonds. A structure that maximizes the use of tax-exempt bonds will ultimately provide the lowest cost of financing to the JPA.

3.4. Implementation Models

There are a variety of approaches a community may take when implementing a CCA program. The approaches vary depending on the amount of operational control and the potential benefits and risks assumed by the community.

3.4.1. Single Third-Party Supplier

At one end of the spectrum, the CCA may choose to out-source administrative responsibilities of the program to a third-party energy supplier. The CCA essentially serves as a liaison between electric customers of the CCA and the third-party energy supplier. It would have no hands-on administrative responsibilities.

To develop such an arrangement, the community must first solicit offers from electric suppliers to serve its customers. In its request for bids, the CCA would detail its desired administrative framework, which would largely rely on the energy supplier to perform the necessary administrative functions of the program. During negotiations with the prospective energy supplier, the CCA may choose to include provisions that guarantee discounts relative to IOU rates. This would transfer cost-specific risks from the CCA to the energy supplier.

This approach offers very little risk to the community, but it also limits the potential for significant financial savings, particularly when considering the foregone benefits of municipal-financing (the financing of locally owned generation assets). A CCA should also consider that energy suppliers may not be willing to agree to such an approach. The energy supplier may feel that certain risks, such as changes in IOU rates or the CRS, are not manageable.

Because it is unlikely that suppliers would charge less than the market price of electricity, potential cost savings would be doubtful. The additional costs imposed by the CRS would put program costs above those charged by the market and, likely, the IOU. Bids from electricity suppliers should be obtained early in the CCA's implementation planning process to help determine whether this approach is viable.

3.4.2. Multiple Third-Party Service Providers

In this approach, the community would *unbundle* program services and would negotiate individual contracts with third parties for each discrete service (e.g., billing service, scheduling coordination, electric supply). The CCA would assume overall responsibility for the program and for the performance of its contractors. In this scenario, the CCA would retain responsibility for rate-setting, establishing program policies, and general administration of the program.

This approach offers several advantages to the CCA, including limited staffing requirements, increased administrative control (when compared to the Single Third-Party Supplier option above), diffusion of risk (associated with supplier default), and accumulation of industry knowledge and experience (gained through the execution of day-to-day administrative responsibilities and interaction with service contractors). Under this approach, the CCA would be independently accountable for the results achieved by the program, regardless of success or failure.

3.4.3. Municipal Operations

In the longer term, the community could develop the organizational structure required to operate all aspects of the CCA program using in-house staff and resources. Recruiting skilled professional staff with electricity operations experience could be challenging and may not be feasible for most CCAs in the initial years. Over time, as the CCA gains experience with the program, some or all of the functions that were initially outsourced could be brought in-house.

3.5. Getting Quotes From Suppliers and Operators

A request for bids (RFB) should be used to screen potential suppliers for qualifications and obtain price offers for the services required. A single RFB can be used for electric supply as well as the customer account services that are needed for operation of a CCA program. Developing the RFB requires forethought and good definition of the desired services, including parameters of how bids should be structured. The goal should be to obtain responsive bids that can be compared on an apples-to-apples basis. A good approach is to establish minimum bid requirements from bidders and allow for submission of creative alternatives in addition to the minimum requirements bids. The RFB should be conducted after the basic program implementation approach has been decided but before the formal IP is submitted to the CPUC.

There are several steps involved in developing an RFB for services needed by the CCA program:

- Develop forecast of customers and annual kWh sales for the primary customer classifications (residential, commercial, industrial, agricultural, street lighting, etc.).
- Define customer load profiles: monthly kWh and KW by class, hourly kW by class.
- Specify desired length of contract terms and dates upon which service will commence and terminate.
- Identify the specific services requested, such as full requirements for electricity, renewable energy, and customer account services (customer enrollment, bill calculations, payment tracking, and customer services).
- Determine whether prices should be fixed, indexed, or a combination of fixed and indexed prices.
- Determine the schedule for RFB release, bidders' conference, responses due, evaluation, contract negotiation/due diligence, and contract execution.

- Specify minimum bid requirements including, for example, the need to meet minimum renewable portfolio requirements and resource adequacy standards.
- Develop a standard bidder's template and format for offers.
- Consider whether alternative bid structures will be accepted.
- Define requirements for qualification, including requiring financial statements, credit ratings, and references.
- Determine whether specific resource types are desired (renewable types, natural gas-fired, etc.).
- Determine evaluation criteria.
- Determine recipients of RFB, e.g., public posting, pre-screened suppliers, and/or industry press.

3.6. Phasing?

CCAs will not be required to serve all their customers from Day One. CPUC decisions allow CCAs to phase in their programs. There may also be clear benefits to phasing in program operations, such as:

- Phasing in service can reduce implementation risk by enabling a pilot program to work out any glitches before rolling the program out to all customers.
- A phased implementation approach can help eliminate potential cash problems that might otherwise occur in the early years of CCA implementation.

AB 117 does not prohibit a CCA from offering service to a portion of the customers within its jurisdiction. However, AB 117 clearly states that CCAs must offer service to *all residential customers*. Presumably, the transfer of residential accounts could be phased in without violating the residential *must-offer* requirement.

The CPUC has stated that the decision to establish a phase in or pilot implementation program should be determined by the CCA, not the IOU or CPUC. The CPUC also found that a phase in or pilot program may impose additional costs on an IOU that can be recovered from the CCA. Conversely, some phase in plans may actually reduce IOU costs. The IOUs are permitted to negotiate with CCAs regarding phase-in plans that may reduce costs.

3.7. Developing a Marketing Campaign

Any local government wishing to establish a CCA program needs to fully inform its residents, businesses, institutions, and municipal departments of its interests/ intentions. This informational campaign should start very early in the investigative process in order to secure stakeholder buy-in.

Switching from a known supplier (an IOU) to a largely unknown, new energy provider will be a concern for large energy users, and just about everyone else. Business owners will require assurances with respect to service reliability (this should not be a problem since the IOUs will continue to deliver the power and maintain the transmission and delivery system for their own customers as well as those of the CCA), price stability, and cost savings. Other constituents may have different concerns, such as those affected by low-income subsidies, or those interested in opportunities for energy efficiency.

Involving the constituents early and often will instill a feeling of ownership during decision-making processes, and, ultimately, in the local government's final determination with respect to CCA implementation. Anyone who decides to approach the city council or county board of supervisors with a CCA plan that has not been fully vetted in a public forum should expect major opposition. San Francisco and Chula Vista have scheduled multiple community workshops in an effort to make important information readily available to community members.

Similarly, the East Bay communities of Berkeley, Emeryville, and Oakland have established a process involving joint stakeholder workshops to solicit and gather community input during the decision-making stage. These communities will utilize the information collected in these forums to develop the best possible structure for a joint CCA in the event that the decision to form a CCA is approved. Each city will also use education campaigns for its own constituents. Marin County is developing a process similar to that of the East Bay communities.

Local governments considering CCA should also develop a marketing plan and related materials. This can be completed during the community workshop stage and will be critical in educating residents and businesses owners before customers are switched from the IOU to the CCA. Cities and counties interested in CCA formation should check with other communities that have established, or are in the process of establishing, a CCA program to discuss ideas and materials. They should also use as many of their own resources/publications as possible (water and garbage bills, tax notices, etc.) to inform and educate members of their community.

As part of the implementation process, CCA programs must provide two distinct notices to potential customers at least 60 days before CCA operations begin. These notices must include instructions on how to opt out of the CCA program. Opting out of CCA service means the customer continues to receive electric services from an IOU (all CCA customers remain IOU customers for transmission and delivery; CCAs will provide the electric commodity only). CCAs must provide two additional notices within 60 days after CCA operations start.

Without a concerted effort to educate all community constituents prior to the first opt out notification, there will be many questions to answer during this period. Ultimately, a lack of communication may result in many customers remaining with IOU service. A CCA should establish a call center before the start of operations to help address questions and concerns before the opt-out notification period.

3.8. Requirements After Filing the Implementation Plan

Filing an Implementation Plan with the CPUC activates certain timelines and related requirements:

- The CPUC will notify the IOU within 10 days of IP filing that the CCA has filed the plan.
- Within 90 days of IP filing, the CPUC shall certify that it has received the IP, including any additional information necessary to determine cost recovery surcharge. The CPUC shall designate the earliest possible date for implementation of a CCA program.
- The CCA must offer the opportunity to purchase electricity to all residential customers within its political boundaries, although the IP can include a plan for phasing in community participation.
- The CCA must fully inform all customers of their right to opt out of the CCA program and to continue receiving service as a bundled customer from the IOU. All customers must be notified twice within 60 days prior to the date of automatic enrollment. In addition, notification must continue for participating customers for at least two consecutive billing cycles after enrollment.
- Customer notification must contain the following information:
    - Those customers will be automatically enrolled.
    - That each customer has the right to opt out of the program without penalty.
    - The terms and conditions of CCA service.
- The CCA may request the CPUC to order the IOU to provide these customer notifications in its regular monthly billing at the CCA's expense.
- The CCA must register with the CPUC and may be required to provide additional information in order to verify compliance with rules for consumer protection and other procedures. At the time of registration, the CCA must post a bond or provide evidence of sufficient insurance to cover any reentry fees that may be imposed against it by the CPUC for involuntarily returning a customer to service of the IOU.
- The CCA must notify the IOU when its service will begin within 30 days.
- Once notified, the IOU shall transfer all applicable accounts to the new supplier within a 30-day period from the date of the close of their normally scheduled monthly metering and billing process.
- The IOU shall recover from the community any costs reasonably attributable to the CCA, as determined by the CPUC.

3.9. Model Implementation Plan

URL to plan: http://lgc.org/cca/index.html

Glossary of Terms

Word	***Definition***
Assembly Bill 117 (Migden, Chapter 838, Statutes of 2002)	AB 117 grants cities and counties, or groups of them, the authority to competitively procure electric services rather than continuing to rely on the IOU as the supplier for electric services to customers within the community. AB 117 was signed into law in 2002. It has been integrated into California's Public Utilities Code, primarily in Section 366.2, but with other provisions in Sections 218.3, 331.1, 366, 381.1, 394, and 394.25.
Assembly Bill 1890 (Brulte, Chapter 854, Statutes of 1996,)	AB 1890 was California's electricity restructuring legislation signed by Governor Wilson in 1996. It allowed customers to purchase electricity from providers other than the monopoly utilities. The utilities were required to divest their thermal power plants in an effort to make the market more competitive. They therefore had to purchase about half of their electricity from the market. Residential consumers were given a 10% rate decrease and a cap on what they could be charged until the utilities paid off their uneconomic assets.
Aggregator	An aggregator is an entity responsible for procuring, planning, scheduling, accounting, and settling electricity deliveries for electricity supplies to a group of end customers.
Base Load	Base load is the lowest level of power production needs during a season or year. Base load power plants generally operate continuously due to long startup times. Electricity from base load plants is generally the cheapest. To meet demand, base load electricity is supplemented with peak load and spot market supplies.

Word	Definition
Bill-Ready Billing	Bill-ready billing is one of two methods that a CCA can use to invoice its customers. It requires the CCA to apply its rate schedule to the electricity used by each of its customers and then provide the utility with the amount to charge. Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric can process bill-ready billing.
Bundled Customers	Bundled customers of investor-owned utilities (IOUs) are the customers who are not allowed to choose another electricity provider, or who remain with the IOU after a CCA is formed.
California Alternate Rates for Energy (CARE)	CARE Program provides a 20 percent discount on monthly bills for qualified low- or fixed-income households and housing facilities. Qualifications are based on the number of people living in the home and the total annual household income.
California Department of Water Resources (DWR)	The Department of Water Resources stepped in to purchase electricity for the utilities following the energy crisis of 2000-2001. It negotiated contracts with energy suppliers and issued bonds to cover some of its costs. All customers of the utilities during that crisis period will to continue to pay these costs until they are fully paid.
California Energy Commission (Energy Commission)	The California Energy Commission is the sponsor of the pilot program to investigate CCA feasibility that produced this guidebook.
California Independent System Operator (California ISO)	The California Independent System Operator is a not-for-profit public-benefit corporation charged with operating the majority of California's high-voltage wholesale power grid. California ISO is the link between power plants and utilities, and balances the demand for electricity with an equal supply of megawatts.
California Public Utilities Commission (CPUC)	The California Public Utilities Commission is the state agency charged with oversight of the investor-owned utilities and with implementing AB 117. The CPUC has instituted a rulemaking, and issued two decisions on community choice aggregation.

Word	***Definition***
Capacity	Capacity is the amount of electric power for which a generating unit, generating station, or other electrical apparatus is rated either by the user or manufacturer.
Capacity Factor	Capacity factor is a percentage that tells how much of a power plant's capacity is used over time. For example, typical plant capacity factors range as high as 80 percent for geothermal and 70 percent for cogeneration.
Community Choice Aggregation and Community Choice Aggregator (CCA)	These terms are used interchangeably. Any city or county whose governing board elects to combine the loads of its residents, businesses, and municipal facilities in a community-wide electricity buyers program; or any group of cities, counties, or cities and counties whose governing boards have elected to combine the loads of their programs, through the formation of a joint powers agency, as long as that entity is not within the jurisdiction of a local publicly owned electric utility that provided electric service as of January 1, 2003.
Competitive Transition Charge (CTC)	The CTC is a charge authorized by the California Public Utilities Commission that is imposed on investor-owned utility customers to recover the costs of utility investments made on behalf of their customers. The CTC is to be collected in a competitively neutral manner that does not increase rates for any customer class solely due to the existence of transition costs.

Word	***Definition***
Cost Responsibility Surcharge (CRS)	The CRS is charged to CCA customers to offset any negative impact CCA formation may have on the rates of an investor-owned utility's (IOU) remaining bundled customers. It is determined by comparing the required rates for all IOU customers (including the ones about to leave for a CCA program) to the required rates of the IOU without the departing CCA customers. Components of the CRS include high-cost contracts signed by the Department of Water Resources (DWR) and the IOUs following the energy crisis of 2000 and 2001, DWR bond costs, and other high-priced generation assets of the IOUs.
Delivery Service	Delivery service is the delivery of power over investor-owned utility transmission and distribution facilities.
Demand-Side Management	Demand-side management includes actions taken on the customer's side of the meter to change the amount or timing of energy consumption.
Departing Load	Departing load is the amount of electricity that will no longer be supplied by an investor-owned utility due to direct access, self-generation, or community choice aggregation.
Deregulation	Deregulation or restructuring is the opening of previous monopoly markets for electricity. In California, AB 1890 restructured the electricity market to allow other suppliers to compete with the investor-owned utilities for customers.
Direct Access (DA)	Direct access is the ability of a retail customer to purchase commodity electricity directly from the wholesale market rather than through a local distribution utility. Currently only direct access customers who were in signed agreements before the process was suspended following the energy crisis of 2000 and 2001 can participate. No new direct access agreements have been allowed since 2002.

Word	*Definition*
Distribution System	A distribution system is the means of the delivery of electricity to the retail customer's home or business through low-voltage distribution lines.
Distributed Generation (DG)	A distributed generation system involves small amounts of generation located on a utility's distribution system for the purpose of meeting local loads and/or displacing the need to build additional (or upgrade) local distribution lines.
End-Use Customer (End-user)	An end-use customer is a residential, commercial, agricultural, or industrial electric customer who buys electricity to be consumed as a final product (not for resale).
Energy Efficiency	Energy efficiency is using less energy to perform the same function. An example would be replacing an incandescent light bulb with a compact fluorescent light (CFL) bulb that produces the same amount of light. CFLs generally use about ¼ of the energy of incandescent bulbs to produce the same amount of light.
Energy Service Provider (ESP)	ESPs are third-party operators or energy services providers, such as marketers or aggregators, who provide electricity directly to an end-use customer in the direct access market.
Exit Fees	Once a CCA program begins, its customers will have 60 days to opt out at no cost. After the initial 60 days, *exit fees* may be imposed to cover any financial commitment the local aggregator has made to power suppliers on a customer's behalf. For the majority of residential customers, such exit fees will be small, since most residents, and many small businesses, are relatively small consumers of electricity.
Federal Energy Regulatory Commission (FERC)	The Federal Energy Regulatory Commission is an independent agency that regulates the interstate transmission of natural gas, oil, and electricity. FERC also regulates natural gas and hydropower projects.

Word	***Definition***
General Rate Case	General rate case is the filing that an investor-owned utility makes to the CPUC to adjust the rates it charges its customers.
Generation Services	Generation services are power plants that produce electricity.
Green Energy	Green energy is usually defined as non-polluting, renewable energy such as solar photovoltaics, solar thermal, wind, geothermal, and landfill gas. Different entities use different definitions.
Implementation Plan	Implementation plans are required of potential CCAs. They must be adopted at a public meeting of the city, county, or joint cities and counties that will file the plans with the CPUC. They have certain requirements in the law. The CPUC will use the implementation plans to determine the cost responsibility surcharge for a CCA's customers.
Investor-Owned Utility (IOU)	For purposes of the CCA Program, IOU refers to Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company, the three electrical corporations whose ratepayers could switch over to a CCA program.
Joint Powers Agency (JPA)	A JPA is an agreement between more than one government entity to cooperate on a particular program or project. A JPA can be between all levels of government (local, state, and federal). Only cities and counties can enter into a JPA to establish and operate a CCA.
Kilowatt (kW)	The kilowatt is a unit for measuring power, equal to one thousand watts. A kilowatt is roughly equivalent to 1.34 horsepower.
Kilowatt-Hour (kWh)	A kilowatt-hour is the most commonly used unit of measure telling the amount of electricity consumed over time. It equals one kilowatt of electricity supplied for one hour. A typical California household consumes about 500 kWh in an average month.

Word	***Definition***
Levelized Cost	To compare the cost of a wide variation of generation types, a levelized cost method is used. Levelized cost considers the total electrical energy that a power plant will produce in its lifetime and it is divided by the total cost of construction along with the interest and the cash flow during construction plus the operation and maintenance cost. Everything is compared using present money worth.
Liquified Natural Gas (LNG)	Natural gas that has been condensed to a liquid, typically by cooling the gas to minus 260 degrees Fahrenheit (below zero), or 162 degrees Celsius (below zero).
Local Governments	California cities, counties, or city and county joint powers agencies count as local governments for the purposes of CCA. Special districts cannot form a CCA.
Load Profile	The electricity uses of all of the customers of a load-serving entity are added together for each hour of the day for a full year to develop its load profile.
Load-Serving Entity (LSE)	Load-serving entities are the organizations that directly provide electric power to end-use customers.
Megawatt (MW)	The megawatt is equal to one million (10^6) watts. The productive capacity of electrical generators operated by utility companies is often measured in MW. A typical modern nuclear power plant produces a peak output on the order of 500 to 2000 MW.
Municipalization	Municipalization is the act of forming an electric municipal utility by replacing the existing IOU with a locally owned electric utility and involves securing the infrastructure to deliver electricity either by new construction or by condemnation by eminent domain of the wires and poles of the IOU.

Word	***Definition***
Municipal Utility	A municipal utility is a local publicly owned (customer-owned) electric utility that owns or operates electric facilities. Examples include the Los Angeles Department of Water & Power and the Sacramento Municipal Utility District. There are many smaller examples around the state.
Non-dispatchable	Non-dispatchable resources are ones that cannot be turned on and off when needed. Solar and wind are non-dispatchable since they are available only when the sun is shining or the wind is blowing.
Northeast Ohio Public Energy Council (NOPEC)	NOPEC was formed in 2000 as a public aggregation to purchase electricity on behalf or residents and small businesses in member communities. Today, NOPEC consists of 116 member communities and is the largest public energy aggregator in the United States.
Open Season	Open season allows a CCA to commit to a date on which responsibility for customer power purchases will switch from the IOU to the CCA. The Open Season is strictly voluntary and will occur annually from January 1 to February 15 or March 1, depending upon the timing when the California Energy Commission's resource adequacy forecasts are due. The primary objectives of the open season process are to reduce costs incurred by CCAs and the IOUs, and to provide a mechanism for coordinating a CCA's transfer of customers.
Opt In/Opt Out	An aggregation program that is *opt out* automatically enrolls all customers within the aggregator's territory. Customers may opt out of the aggregator's program to remain as customers of the utility. An *opt in* aggregation program requires each customer to individually agree to join the program.
Pacific Gas and Electric (PG&E)	Pacific Gas and Electric is the investor-owned utility serving most of Northern California.

Word	Definition
Peak Load	Peak load indicates the additional demand placed on a system, above the normal base load needs. Peaking power plants can respond quickly to changes in demand. Peak load electricity generally costs more than base load.
Phasing or Phasing In	AB 117 requires that any CCA program offer electricity to all of the residents in the CCA's territory. The law and the rules decided by the CPUC allow a community to phase in operations. That is, the CCA does not have to serve all of its customers on the first day of operations. It can add them in steps over a period, as long as all residential customers are eventually offered service.
Photovoltaic (PV)	Photovoltaic is a solar power technology that uses solar cells or solar photovoltaic arrays to convert light from the sun directly into electricity.
Power Purchase Agreement (PPA)	A power purchase agreement is a contract for the purchase of electrical energy and/or capacity.
Production Tax Credits	A renewable production tax credit can be thought of as a reward that the federal or state government pays to companies that generate energy from renewable sources such as wind power. The federal government currently offers a renewable production tax credit of 1.8 cents per kilowatt-hour. As a tax credit, it can only be used to reduce the amount of taxes a firm owes. Non-tax-paying entities such as a CCA can take advantage of the similar Renewable Energy Production Incentive.
Public Interest Energy Research (PIER)	The California Energy Commission's Public Interest Energy Research (PIER) Program supports energy research, development and demonstration (RD&D) projects that will help improve the quality of life in California by bringing environmentally safe, affordable and reliable energy services and products to the marketplace. The PIER Program funded this project and guidebook.

Word	***Definition***
Qualifying Facility (QF)	QFs are non-utility power producers that often generate electricity using renewable and alternative resources, such as hydro, wind, solar, geothermal, or biomass (solid waste). QFs must meet certain operating, efficiency, and fuel-use standards set forth by the Federal Energy Regulatory Commission (FERC). If the QFs meet these FERC standards, utilities must buy power from them. QFs usually have long-term contracts with utilities for the purchase of this power, which is among the utility's highest-priced resources.
Rate-Ready Billing	With rate-ready billing, the CCA provides the rate schedule to the utility that applies it to customer usage to develop the charge amount. PG&E is the only utility to offer rate-ready billing, but for fewer tiers of service than its own rate schedule. This will make it difficult for consumers to compare the CCA's rates to PG&E's.
Renewable Energy	Renewable energy comes from resources that constantly renew themselves or that are regarded as practically inexhaustible. These include solar, wind, geothermal, hydro, and biomass. Although particular geothermal formations can be depleted, the natural heat in the Earth is a virtually inexhaustible reserve of potential energy. Renewable resources also include some experimental or less-developed sources such as tidal power, sea currents, and ocean thermal gradients.
Renewable Energy Credits (REC)	Renewable energy credits are tradable units that represent the commodity formed by unbundling the environmental attributes of a unit of renewable energy from the underlying electricity. Under most programs, one REC would be equivalent to the environmental attributes of one megawatt-hour of electricity from a renewable generation source.

Word	***Definition***
Renewable Energy Production Incentive (REPI)	The Renewable Energy Production Incentive (REPI) provides financial incentive payments for electricity produced and sold by new qualifying renewable energy generation facilities. Qualifying facilities are eligible for annual incentive payments of 1.5 cents per kilowatt-hour (1993 dollars and indexed for inflation) for the first 10-year period of their operation, subject to the availability of annual appropriations in each federal fiscal year of operation.
Renewables Portfolio Standard (RPS)	California's Renewables Portfolio Standard requires retail sellers of electricity to supply 20% of their electricity from renewable resources by 2010. Eligible renewable resources include biomass, solar thermal, photovoltaics, wind, geothermal, fuel cells using renewable fuels, small hydropower of 30 megawatts or less, digester gas, landfill gas, ocean wave, ocean thermal, and tidal current. Municipal solid waste is generally eligible only if it is converted to a clean-burning fuel using a non-combustion thermal process.
Renewable Resources Development Report (RRDR)	The Renewable Resources Development Report is organized to provide an indication of changes in development of renewable energy resources over time, moving from past to present to future. It provides a historical context for renewable electricity generation in California and the other states in the Western Electricity Coordinating Council (WECC). The renewable resources included in this report are wind, geothermal, biomass, biogas, solar photovoltaic, concentrating solar power, small hydroelectric, and ocean energy.
Revenue Requirement	The revenue requirement for a utility or CCA is the amount of money that must be collected from ratepayers to cover its costs.
Rulemaking 03-10-003	The California Public Utilities Commission established Rulemaking 03-10-003 to decide the implementation issues of CCA. Decisions were adopted in December 2004 and December 2005.

Word	***Definition***
San Diego Gas & Electric Company (SDG&E)	San Diego Gas & Electric Company is the investor-owned utility that serves the San Diego area with gas and electricity.
San Joaquin Valley Power Authority (SJVPA)	The SJVPA is the first entity in California to file a Community Choice Aggregation Implementation Plan with the CPUC. The SJVPA plans to start serving customers in November 2007.
Self-Generation	Self-generation is a generation facility dedicated to serving a particular retail customer, usually located on the customer's premises. The facility may either be owned directly by the retail customer or owned by a third party with a contractual arrangement to provide electricity to meet some of the customer's entire load.
Sensitivity Analysis	A sensitivity analysis allows a researcher to model the best- and worst-case scenarios for variables. For example, starting with the expected future cost of natural gas for the next 20 years, a sensitivity analysis might test the impacts of natural gas cost that is 25% higher or lower than the expected cost.
Southern California Edison Company (SCE)	Southern California Edison Company is the investor-owned utility that serves most of Southern California outside the San Diego area with electricity.
Spot Market	Spot market purchases and sales are used to fill the load requirements that remain after using both long-term and short-term contracts and/or CCA-owned generating resources.
Statement of Intent	Along with an implementation plan, a CCA must file a statement of intent with the CPUC that addresses universal access, reliability, and customer class equity.

Word	***Definition***
Supplemental Energy Payments (SEP)	Production incentives, referred to as supplemental energy payments (SEPs), will be awarded to eligible renewable generators for the above-market costs of eligible electricity procurement by California's three largest investor-owned utilities (IOUs) to fulfill their Renewables Portfolio Standard obligations.
Transmission System	The transmission system is an interconnected group of electric transmission lines and associated equipment used to move or transfer electric energy in bulk between points of supply and consumption.
Utility-Retained Generation (URG)	Utility-retained generation is a term for the power plants the utilities did not divest, such as nuclear power plants and hydro-electric facilities.
Vintaging	Vintaging is a term used to describe the how CCAs could have different cost responsibility surcharges based on when they commence serving their customers.
Wheeling Electricity	Wheeling is the transmission of electricity by an entity that does not own or directly use the power it is transmitting. Wholesale wheeling is used to indicate bulk transactions in the wholesale market, whereas retail wheeling allows power producers direct access to retail customers.

Appendix A

Sample Data Request Letters

[DATE]

Pacific Gas & Electric Company
Governmental Affairs
Attention: [LOCAL GOVERNMENTAL AFFAIRS REPRESENTATIVE]
77 Beale Street
San Francisco, CA 94105

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

Dear [LOCAL GOVERNMENTAL AFFAIRS REPRESENTATIVE]:

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

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

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

   The [CITY OR COUNTY] requests the total number of customers and monthly energy consumption in kWh for the following rate groups: residential (E-1 and all other residential services), small commercial (A-1, A-6), medium commercial (A-10), small industrial (E-19), large industrial (E-20), agricultural, and outdoor and street lighting. Please provide the above information separately for customers currently receiving bundled utility service from PG&E and customers currently served under direct access arrangements with energy service providers.
2. System-wide residential and nonresidential load shapes and most recent hourly load shapes for the climate band encompassing the [CITY OR COUNTY].
3. The proportional share in the potential CCA territory, as defined in the CPUC's energy efficiency policy manual.

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

Please send this information in electronic form via e-mail to [E-MAIL ADDRESS]. The [CITY/COUNTY OF NAME] appreciates your assistance.

Sincerely,

[DATE]

San Diego Gas & Electric Company
Attention: [LOCAL GOVERNMENTAL AFFAIRS REPRESENTATIVE NAME]
101 Ash Street
San Diego, CA 92101

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

Dear [LOCAL GOVERNMENTAL AFFAIRS REPRESENTATIVE NAME]:

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

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

- Aggregate annual usage data (kWh) broken out by city, zip code, and customer and rate classes, on a monthly basis.
- Public Goods Charge customer payments by zip code and city. Quarterly or monthly aggregated participation data already tracked for CPUC reports.
- The proportional share in a CCA's territory or proposed territory as defined in the CPUC's energy efficiency policy manual.

Please include the number of electric service accounts in the first bullet above and separate the information between customers currently receiving bundled utility service from SDG&E and customers currently served under direct access arrangements.

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

Please send this information in electronic form via e-mail to [E-MAIL ADDRESS]. The [CITY/COUNTY OF NAME] thanks you for your assistance.

Sincerely,

[DATE]

Southern California Edison Company
Attention: [LOCAL GOVERNMENTAL AFFAIRS REPRESENTATIVE NAME]
PO Box 800
2244 Walnut Grove Ave,
Rosemead, CA 91770

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

Dear [LOCAL GOVERNMENTAL AFFAIRS REPRESENTATIVE NAME]:

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

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

- Number of accounts in each rate group.
- Aggregate consumption (monthly kWh) for each rate group.
- Aggregate noncoincident demand in each rate group where metered demand data is available.
- Coincidence factors which estimate coincident demands where metered data is available.
- Standard system average load profiles by rate group, to estimate load shapes.
- The proportional share in the potential CCA territories, as defined in the CPUC's energy efficiency policy manual.

Please separate the information in bullets 1 and 2 above between customers currently receiving bundled utility service from SCE and customers currently served under direct access.

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

Please send this information in electronic form via e-mail to [E-MAIL ADDRESS]. The [CITY/COUNTY OF NAME] thanks you for your assistance.

Sincerely,

Appendix B

Key Assumptions Used in CCA Feasibility Analysis and Modeling for the California Energy Commission Pilot Project Feasibility Studies Completed in 2004 and 2005

1) Metering and Billing
    a) No new metering requirements for CCA customers.
    b) Billing charges same as direct access from Schedules E-ESP and E-EUS.
    c) Billing charges based on Rate Ready Billing Option from Schedule E-ESP.
2) Financing
    a) Tax exempt financing for startup costs and any new generation development @ 5.5%.
    b) 100% debt financing.
    c) Financing term is 30 years.
    d) Minimum debt coverage ratio of 1.25.
    e) Bond insurance cost of 1.6% of par value.
    f) Bond transaction cost of 1% of par value.
    g) Debt reserve of 10% of par value.
3) Startup and Operations Costs
    a) Startup costs include regulatory and legal @ $350,000.
    b) Operational costs are outsourced @ $2.50 per MWh unless and until CCA reaches approximately 1.5 million MWh in sales.
    c) If performed internally, the cost is estimated at $3.9 M per year plus 10 cents per MWh, including Information Technology (IT).
    d) Activities include scheduling coordination, procurement/planning, risk management, credit, rates and load research, Administration and General, and IT.
    e) The CCA will begin serving customers in January 2006.
4) Resource Adequacy
    a) CCAs subject to same resource adequacy requirement as IOUs, per D.04-01-050.
    b) Planning reserves are required to bring total reserves, including CAISO-required ancillary services, up to 15% of peak load.
    c) Costs of meeting planning reserves equal to market value of capacity.
    d) Spot market purchases limited to between 5% and 20% of CCA portfolio; the remainder of the portfolio is comprised of long-term contracts and/or resource ownership.
5) Renewable Energy Portfolio
    a) Renewable purchases are from a generic portfolio comprised of Class 4 Wind, Binary Geothermal, Solid Fuel Biomass, Land Fill Gas Biomass, and Concentrating Solar Power.

b) The cost and resource mix comprising the portfolio is derived from the Energy Commission's *Renewable Resources Development Report* (RRDR) (2003). See RRDR Table 4, page 37 and discussion at page 87. Costs from the year 2005 are escalated at a nominal rate of 1% per year.

c) The cost of the generic renewables portfolio equals the estimated developers' costs, including return on investment. Market price of renewable energy equal to maximum of cost or market price of system energy.

d) The cost of wind energy assumes no extension of the production tax credit.

e) Wind energy must be firmed via capacity contracts due to its intermittent nature. The cost of wind energy is adjusted for a capacity adder to firm the intermittent resource, at market value of capacity.

f) Renewable ownership costs are derived by applying municipal financing assumptions to the cost data in RRDR Appendix D, page D-6. 2005 costs are escalated at a nominal rate of 1% per year.

g) Ownership cost incorporate technology-specific assumptions regarding installed capital costs, fixed operations and maintenance, capacity factor, fuel cost, and capacity cost adder applied to intermittent resources.

h) The ownership costs of intermittent resources also include a risk factor of $5 per MWh related to the potential differences between energy prices for sales from excess production versus purchases for production shortfalls.

i) CCAs will rely primarily on large-scale renewable projects to meet and exceed the RPS. These are wind, geothermal, solid fuel biomass, and concentrating solar power.

j) CCA-owned generation resources can be online by 2008.

k) Distributed generation options, such as rooftop PV systems, are incorporated in the feasibility analysis based on community-specific planning. Renewable distributed generation production, if any, will be in addition to the RPS minimums.

l) Supplemental energy payments are available to offset the incremental costs of renewable contract purchases (10-year terms) up to the minimum RPS requirement. Public Goods Charge funds are sufficient to buy down 100% of the cost premium of renewables.

m) Supplemental energy payments are not available for city-owned resources and are not available for purchases in excess of the RPS minimums.

n) CCAs are required to match the renewable energy percentage of the respective investor-owned utility in the first year of CCA operations.

o) IOU renewable baseline percentages are derived from RRDR Appendix A, page A-2 and increased by 1% per year until 20% is achieved by 2010.

6) Wholesale Energy Markets

   a) Electricity market price forecast based on projected market clearing system heat rates and natural gas price projections.

   b) Natural gas price projections prepared by Navigant Consulting, Inc. in January 2005.

   c) Implied system clearing heat rates for 2005-2010 are 8,000, 8250, 8700, 9000, 10,000, and 10,500. Market equilibrium assumed at implied system heat rate of 11,000 after 2010.

   d) On-peak energy priced at 15% premium; off-peak energy priced at 15% discount; real time energy at 10% premium.

   e) Long-term contracts priced at 5% premium to expected spot market prices.

   f) Capacity costs valued at $100,000 per MW-Year, escalated at 2.5% annually; costs are embedded in energy prices derived as above.

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

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

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

   j) CAISO administrative and neutrality charges are derived from current rates, escalated at 2.5% annually.

   k) CAISO charges are Grid Management Charge - Control Area Service, Grid Management Charge - Inter-zonal Scheduling, Grid Management Charge - Ancillary Services and Real Time Operations, Unaccounted for Energy Charge, Neutrality Charge, and Congestion Charge.

   l) No explicit modeling of impact from move to locational marginal pricing; assumed that loads will be protected from congestion costs by allocation of congestion revenue rights and zonal averaging of prices.

   m) Distribution losses are 7%.

7) Generation Cost

   CCA's choosing to own generation will acquire equity interests in combined cycle gas turbine facilities based on the following cost and operating parameters:

   a) Installed cost of $700 per KW.

   b) Heat rate of 7,000 mmbtu/MWh.

   c) $3 per MWh fixed and variable operations and maintenance.

   d) 0.1 pounds per MWh emissions.

   e) $10 per pound cost of Nitrous Oxides (NOx) emissions.

   f) 90% planned capacity factor.

- g) 2% forced outage rate.
- h) Excess sales sold at prevailing market clearing prices.

8) Cost Responsibility Surcharges

- a) Cost Responsibility Surcharges (CRS) calculated annually using total portfolio indifference method adopted in direct access proceeding (includes old and new resources) (R.02-01-011) and CCA Rulemaking (D.04-12-046).
- b) CRS reduced by pro rata share of cost of ancillary services and planning reserves.
- c) No cap on CRS for CCAs.
- d) CRS includes DWR bonds, DWR power charge, utility Competitive Transition Charge (CTC), and Regulatory Asset (PG&E bankruptcy charge).
- e) Uniform *indifference fee* per KWh for all CCA customers, regardless of rate class and CCA startup date. No baseline credits reflecting Assembly Bill 1X protections for residential consumption up to 130% of baseline allocation.
- f) Uniform DWR bond charge per KWh, statewide.
- g) CTC rate varies by customer class based on current tariffs.
- h) DWR bond charge projections based on currently applicable rate as of January 2005.
- i) No transfer to CCA of DWR contracts, renewable energy, or capacity contracts implied by payment of CRS.

9) IOU Rate Projections

- a) IOU rates for generation are the competitive reference point for assessing CCA cost savings potential.
- b) Current IOU rate schedules (Advice Letter 2570-E-A) as of January 2005 applied to CCA customer billing determinants (estimated), aggregated by major rate group.
- c) Generation rates and total rates (generation plus non-generation) projected forward based on percentage changes in IOU system average rates.
- d) IOU generation costs projected based on current resource mix, adjusted over time for planned generation retirements, DWR contracts, QF contracts, and renewable energy contracts to meet RPS.
- e) PG&E-owned generation resources includes Nuclear (Diablo Canyon), Hydro, and Fossil facilities. Production and sales data are from PG&E's *Long Term Resource Plan*.
- f) Generation costs and beginning rate base for each generation type are derived from 2003 General Rate Case filing.
- g) Generation costs include operations and maintenance, return, depreciation, uncollectibles, A&G, franchise fees, taxes other than income, taxes based on income, fuel, thermal decommissioning, and other.

h) Future capital additions increased for Diablo Canyon turbine replacement anticipated in the 2007–2009 timeframe.

i) Purchased Power includes QF contracts, existing bilateral contracts, DWR contracts, new renewable contracts, new bilateral contracts, and spot market purchases.

j) New bilateral contracts entered into as needed to maintain spot purchases (residual net short) at or below 10% of IOU portfolio.

k) PG&E maintains planning reserves of 15% of annual peak load. Existing ancillary services requirements are included in the 15% planning reserves requirement.

l) Spot market purchases to meet the residual net short are priced at average of NP15 peak (6 X 16) and base (7 X 24) power prices.

m) Majority of QFs (80%) paid according to settlement price through 2005, and then based on annual short run avoided cost formula.

n) QF capacity payments derived from FERC Form 1 data.

o) QF capacity/energy projections derived from the Consultant's Report supporting DWR bond financing.

p) RPS purchases from generic renewable portfolio as described above; Supplemental Energy Payments fully offset incremental costs relative to non-renewable energy.

q) DWR costs and volumes adjusted over time based on terms of the individual contracts allocated to PG&E per D.02-09-053.

r) DWR *remittance rate* calculated using CPUC methodology (D. 04-12-014).

s) Regulatory asset cost calculated based on terms of approved Bankruptcy Settlement.

t) Cost offset for bundled customer generation costs from Cost Responsibility Surcharges paid by direct access Customers based on capped collection rate from direct access proceeding (R.02-01-011).

u) Non-generation costs escalated at constant 1.5% per year. Non-generation rates are only used to express the CCA cost impacts as percentage of customers' total electric bills.

v) Same input assumptions as above for wholesale electricity prices, capacity prices, natural gas prices, ancillary services costs, CAISO charges, RPS % and prices, Supplemental Energy Payments, and DWR bonds charges.

Appendix C

Alternative Financing Methods

Financing Method/ Characteristics	General Obligation Bonds	Limited Obligations Bonds	Special Assessment	Certificates of Participation	Revenue Bonds
Project Financeable	Acquisition and improvements of land and buildings	Acquisition and improvements of land and buildings	Facilities of local benefit to property	Unrestricted	Revenue producing facilities
Authorization	Issuer's governing board and public election (2/3 vote)	Resolution of issuer governing board and 2/3 vote	Resolution of issuer, petition of beneficiaries	Resolution of issuer governing board	Resolution of issuer governing board
Area of Authorization Jurisdiction	Boundary of issuer facilities district (flexible)	Boundary of issuer facilities district (flexible)	Flexible	N/A	Service area of issuer
Hearing Procedure	None	None	Majority protest hearing	Maybe ordinance adoption	None
Validation	None	None	None	None	None
Nature of debt service payments	Unlimited ad valorem tax	Portion of current revenues	Annual assessments based on benefits received; property taxes may not be used	Rental or installment payments	Service charges and fees from users
Source of debt service payment	Property owners in issuer jurisdiction	General revenues of issuer	Annual property assessments	General and/or enterprise revenues of issuer	Service charge and fee collections
Security	Full faith and credit	Revenue collections and coverage test	Tax collections/ Foreclosure	Lease or installment sale contract	Coverage test and contracts
Lessor/Lessee Required	No	No	No	Yes	No
Refundable	Yes	Yes	Yes	Yes	Yes
Debt Service Funds Subject to Gann Limit	No	No	No	Yes	Yes
Reserve Fund	No	Yes	Yes	Yes	Yes

Financing Method/ Characteristics	General Obligation Bonds	Limited Obligations Bonds	Special Assessment	Certificates of Participation	Revenue Bonds
Capitalized Interest	No	No	Yes	Yes	New enterprise only
Debt Service Coverage	No	Yes	Value/lien ratio 3:1	No	Yes
Method of Sale	Competitive or Negotiated	Competitive or Negotiated	Competitive or Negotiated	Competitive or Negotiated	Competitive or Negotiated
Advantages	Lower interest rate	No pledge of General Fund	Isolates projects	No voter approval	Higher interest rate
Disadvantages	Voter approval required	Voter approval	Limited security Higher interest rates	Highly structured Limited flexibility	Debt Service Reserve Fund