



**San Francisco
Community Choice Aggregation
Draft Implementation Plan**

Submitted by:

local power

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COMMUNITY CHOICE AGGREGATION IMPLEMENTATION PLAN

**City and County of San Francisco
Local Agency Formation Commission**

Referred to the Board of Supervisors with Recommendation
San Francisco
May 13, 2005

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I. EXECUTIVE SUMMARY

The City and County of San Francisco have elected to become a Community Choice Aggregator to provide electric power and a broad range of related benefits to the citizens and businesses located within its jurisdiction. The City and County of San Francisco are presenting this draft Community Choice Aggregation Implementation Plan in order to aggregate their customer's electric power loads in accordance with State and San Francisco laws that enable communities to form Community Choice Aggregation (CCA) Programs.

In addition, San Francisco's CCA Program will comply with San Francisco Ordinance 86-04, which requires the City and County of San Francisco to implement a combined 360MW of renewable power generation and efficiency and conservation measures. The renewable power generation installed through the San Francisco CCA Program will result in the implementation of one of the highest percentage renewable power mixes nationwide. For these reasons, the implementation of San Francisco's CCA Program will become a significant and historic development in the advancement of the public control over the power supply market.

In the light of the recent Energy Crisis and the ongoing financial issues affecting many Investor Owned Utilities, a publicly controlled CCA will provide both cost reductions and increased electric power service reliability to its customers. Considering the City and County's peak load levels of approximately 1,000 MW, these measures will bring significant health and environmental benefits when compared to the current carbon based fuel sources used to produce the bulk of the City and County's power.

The new renewable generation will increase power generation reliability by broadening the City's power generation mix. The efficiency and conservation measures will reduce demand, which has the collateral benefit of further enhancing the reliability of the City's power supply and lessening the environmental impacts from conventional sources.

This Implementation Plan provides full descriptions of the measures to be achieved by the City's CCA Program, and the elements of the City's Plan to implement the CCA.

II. INTRODUCTION

1.0 SF CCA Implementation Plan

Pursuant to 366.2(c)(3) of the Public Utilities Code, San Francisco hereby submits its Community Choice Aggregation (CCA) Implementation Plan (IP) to the California Public Utilities Commission.

On May 11, 2004, the San Francisco Board of Supervisors unanimously adopted an "Ordinance establishing a Community Choice Aggregation Program in accordance with California Public Utilities Code Sections 218.3, 331.1, 366, 366.2, 381.1, 394, and 394.25, allowing San Francisco to aggregate the electrical load of electricity consumers within San Francisco and to accelerate the introduction of renewable energy, conservation and energy efficiency into San Francisco's portfolio of energy resources." This was signed by Mayor Gavin Newsom on May 27, 2004, and was entered into the public record during the evidentiary hearings of the California Public Utilities Commission's Community Choice Aggregation proceeding under Administrative Law Judge Kim Malcolm ("Judge Malcolm").

Potential CCA customers in CCSF represent energy purchases larger than the single largest electricity customer in California: the UC/CSU system – a DA customer since 1998. A CCA in CCSF potentially represents about 5% of PG&E's energy sales and 7% of its customers. Given reasonable RFP requirements, it is highly likely that San Francisco as a single customer will be an attractive value proposition to wholesale electric suppliers. For example CCA revenues paid in rates by CCA customers could be \$200 million annually, on par or greater than the City's current water and sewer revenues combined. Due to the electric market context and rules in California, the CCA is likely to engage in multi-year commitments to a supplier and potentially become an owner of new renewable power plants. CCSF could be a market leader in CCA, one of the early, if not the first of its kind in California, operating in a still evolving energy market.

The City and County must take several steps in the process of establishing its Community Choice Aggregation (CCA or "Energy Independence") Program, among the most significant of which is the filing of a Community Aggregation Implementation Plan. Within ten days of receiving San Francisco's IP, the California Public Utilities Commission ("Commission") has 10 days to notify PG&E that an implementation plan initiating community choice aggregation has been filed by the City and County, and another 80 days to request further information from the Board of Supervisors and Mayor, and to certify receipt of San Francisco's IP. After these periods have expired,

Judge Malcolm is hereby requested to promptly present her findings regarding any cost recovery that must be paid by customers of the SFCCA to prevent a shifting of costs, considering the 18 month 2 cents/kwh Customer Responsibility Surcharge (CRS), DWR Bond Charge, and other Commission policies on non-bypassable and exempt forms of generation and loads, including Distributed Generation that qualifies as a renewable under the state Renewable Portfolio Standard, and unforecasted new load on Treasure Island.

The Implementation Plan must address certain items as required by AB117, and this IP addresses each and every element in order to provide Judge Malcolm with the basis on which to present her findings regarding the value of the City's 360 MW commitment, as a three year first phase after which the City will not merely buy green power but permanently remove 14.5% the community's fuel load. This resource will at certain hours of the day eliminate over a third of aggregate peak load of participating customers. With a 51% RPS target now established, by this document, by 2017, under an initial contract with competitively selected Energy Service Provider (ESP) lasting seven to fifteen years, San Francisco's Energy Independence Program will bestow benefits to the grid in reliability, in freed up transmission capacity, avoided substation upgrade costs, fuel purchasing, fuel import load, and other costs.

In order to exceed the green power rules binding PG&E, (an 8% increase in RPS resources by 2017 in addition to the 12% RPS level in 2005) San Francisco will employ its H Bond Authority to finance the renewable power generation facilities built by the City and County's chosen ESP. These facilities will be built within the ESP rate schedule commitment, with all benefits to be distributed among all rate classes, either in their rates or in benefits distributed among ratepayer classes, equitably, on a *pro rata* basis. In order to develop market-scale renewable energy, conservation and efficiency projects instead of merely purchasing Renewable Energy Credits or across the grid power contracts with merchants, the City and County will contract with the ESP for the design, construction, operation, maintenance, and insurance of the 360 MW infrastructure. The ESP shall transfer full title, ownership and control to all H Bond financed facilities to the City and County at the termination of contract with the City and County, or at the time that the H Bonds are repaid.

The 51% RPS goal shall bind the ESP only for the years in which the contract is in effect, such that each year's purchasing requirement shall be adjusted to reflect any delays in construction. The construction schedule will be set in relation to California's current level minimum PG&E schedule that ends with 20% RPS in 2017 - only our goal shall be 51%, and the Board of Supervisors will establish a second goal, in a second RPS rollout phase of 2009 to 2012, to a second phase in which the ESP will enter into a long-term Power Purchase Agreement with the San Francisco Public Utilities Commission to

purchase SFPUC operated wind and other centralized generation capacity projects, committing to build enough additional H Bond financed new facilities to provide 40% of the megawatt hours by 2012, and 51% or higher by 2017.

San Francisco's RPS schedule will thus involve a combination of building and buying. San Francisco's ESP will certainly purchase a great deal of wind capacity from merchant generators and perhaps even Renewable Energy Credits (RECs) from third parties in order to achieve its goal of 51% RPS by 2017, but will set this schedule on an annual basis according to a 51% RPS by 2017 schedule, with 51% "Hard RPS" achieved by 2017. This IP will be geared toward the "hard RPS," not an approach to merely purchase commodity power including an RPS blend. Whereas CCAs that follow a strict RPS approach (in which case the specific impacts on substations, transmission, fuel purchasing and the like may not be ascertained except based on averages) San Francisco will build a permanent infrastructure that will provide power to San Francisco ratepayers and businesspeople for many decades into the future, and physically reduce the amount of power San Franciscans buy, just as permanently. It will result, ultimately, in the closure of the Hunters Point and Potrero power generating plants, through the removal of the Reliability Must Run status of these plants at the Independent System Operator. Thus, the new infrastructure will bestow public health benefits to victims of environmental injustice, bringing both clean air along with employment and economic development benefits to some of the sunnier areas of San Francisco, such as Hunters Point.

San Francisco's Energy Independence structure of financing a portfolio of distributed and centralized renewable resources and conservation facilities, means not only savings in commodity price but hard savings to all ratepayers from lowering the cost of service through load shaving, resulting in lower electric bills from the collective purchasing of less electricity by all members of the community. The benefit is shared with South Peninsula communities, who staunchly and widely opposed the recently approved Jefferson Martin Transmission line, and justly oppose any other new transmission corridors through their neighborhoods. By reducing load as close to the point of energy demand as possible, the City and County will reduce PG&E purchasing and resource adequacy obligations, improving its credit rating and lowering capital costs for all its projects.

San Francisco's plan is not merely to procure more renewable electricity commodity, but, rather, to require its chosen Electric Service Provider to physically deliver this system to San Francisco and the regional transmission system. This means not only development for renewable resources in general, but with an emphasis on local power that makes deeper, systemically profounder commitment to stopping climate crisis and nuclear proliferation, adapting to declining domestic natural gas supplies, and avoiding

any contribution to U.S. energy wars, of which liquefied natural gas (LNG) is already a major component. San Francisco's Energy Independence plan achieves the scale of commitment to facilitate a scaled solution to the continuing energy crisis. It will provide demand for innovative new energy technologies in which Bay Area silicon and turbine prowess has led the world energy industry for decades.

Moreover, the Board and Mayor will not approve any contract with an ESP that would result in a rate increase when customers transfer to the new service, but shall incorporate a "meet or beat PG&E rates" cap for the ESP solicitation. The Board of Supervisors will not attempt to change the rates approved in its ordinance awarding contract to an ESP, except to allow fuel price pass-throughs, which is also the case under utility rates. Thus, the Board is also confident that it can achieve the 51% Hard RPS by 2017. We believe, based on six (6) years of continuous work on this effort, that the 51% RPS schedule will be provided at equivalent or lower rates than those, for each customer class, provided by PG&E, when the 120 day opt-out period required by 366.2(c)(11) terminates.

Moreover, the "build not buy" approach being taken by the City and County offers certainty of rate reductions from a physically lowered cost of serving the San Francisco community for decades to come. While many facilities expected to continue to generate revenue between thirty (30) and eighty-five (85) years, H Bonds issuances will pay back within 15 years, meaning a major free, no-fuel component in its permanent electricity portfolio.

Being ordered by San Francisco's Energy Independence ordinance ("Ordinance 86-04), the IP must conform to the City and County's adopted ordinance, as will a subsequent RFP to be prepared for the Board's amendment and/or adoption three months and thereafter, depending on the Commission's timely action over the 90 day certification period, from the date of the adoption of this Implementation Plan. Any delay on the Commission's part should be assumed to cause an equivalent deviation from the schedule contained herein, including the transfer of customers date and the three year 360 MW rollout schedule. According to this schedule, San Francisco will prepare itself for a departure of all willing electricity customers from PG&E procurement to a chosen ESP, within one year of the adoption of this IP, provided that an ESP can provide the superior service requested at equivalent or lower electric rates for all participating residents and businesses. This is the basic model of Energy Independence, presented within a schedule under which the City and County will publish its CCA RFP within one or two months of its receipt of the Commission's findings regarding any cost recovery to be paid by participating San Francisco ratepayers, including the Customer Responsibility Surcharge.

This resolution hereby provides the Commission with the plan and framework of San Francisco's Energy Independence RFP to the energy industry, in which an ESP will not merely sell commodity electricity "virtually" as a trader, but will finance, and require its ESP to build for its future ownership, the required Hard RPS portfolio elements. This model is adopted City policy in Ordinance 86-04. Another directive of the ordinance was that City and County has prepared, and simultaneously submits with its Implementation Plan, a Statement of Intent that addresses related issues. While the filing of the Statement of Intent with the Commission is not specifically required under AB117, the City and County is including this information with its Implementation Plan.

During the 90-day period prior to CPUC certification of receipt of the Implementation Plan, Commission staff may request information about or clarification of the cost-recovery mechanism pursuant to Section 633.3(d), (e) and (f). The City and County will cooperate with Commission staff in clarifying any outstanding issues concerning cost recovery mechanisms so the Commission can provide certification within 90 days, and requests that in return, Judge Malcolm makes a commitment to provide the cost recovery findings upon the 90th day of that statutory period, so that the City and County may commence its ESP selection process.

The City and County will be coordinating with Pacific Gas and Electric ("PG&E") and Commission staff throughout the City and County's Community Choice Aggregation program development and implementation, and PG&E was presented with a full copy of this Implementation Plan on the same date that it was filed with the Commission.

San Francisco believes that the Commission's actions relative to certain provisions of AB117, as discussed further below, will be critical to the success of its CCA Program.

PUC 366.2 (i) (1) provides that "the Commission shall not authorize community choice aggregation until it implements a cost-recovery mechanism, consistent with subdivisions (d), (e), and (f), that is applicable to customers that elected to purchase electricity from an alternate provider between February 1, 2001, and January 1, 2003." **The Commission implemented a cost-recovery mechanism on December 16, 2004 in R.03-10-003 (D.04-12-046), said that CCAs may commence with implementation immediately, and gave utilities clear orders to immediately facilitate CCA efforts. The City and County is acting directly in response to this invitation by the Commission.**

PUC Section 366.2 (i) (2) provides that "the Commission shall not authorize community choice aggregation until it submits a report certifying compliance with paragraph (1) to the Senate Energy, Utilities and Communications Committee, or its successor, and the Assembly Committee on Utilities and Commerce, or its successor. Therefore, the City

and County requests that the Commission promptly provide the required of its certification to these two committees of the legislature if it has not already done so, as San Francisco is prepared to depart from PG&E procurement, with the final opt-out period terminating 420 days within the adoption of this resolution, and the Implementation Plan which it contains, by the Board of Supervisors.

PUC Section 366.2(i) (3) provides that "the commission shall not authorize community choice aggregation until it has adopted rules for implementing community choice aggregation. **The Commission adopted provisional rules for implementing Community Choice Aggregation on December 16 decision, ordered the utilities to facilitate implementation, and encouraged CCAs to commence implementation, as referenced below. Again, this IP is now filed directly in response to the Commission's invitation.**

Public Utilities Code Section 366.2(c)(8) also provides that "the commission shall designate the earliest possible effective date for implementation of a community choice aggregation program, taking into consideration the impact on any annual procurement plan of the electrical corporation that has been approved by the commission. **Decision 04-12-046 on December 16, 2004 ordered that CCA may commence on the date that PG&E and the other electric utilities filed subsequent interim tariffs with Judge Malcolm in R.03-10-003. As the utilities filed such tariffs in response to this order in February, 2005, San Francisco is hereby commences with its CCA to depart from PG&E procurement within 300 days and initiate installation of the 360 MW project following the opt out period in 420 days.**

This IP is specifically addressed to the need to minimize the impact of the City's decision to proceed with an RFP, and in particular to minimize impacts on PG&E's 2006 and beyond "annual procurement plan," as required by AB117.

The City and County hereby requests a finding by Judge Malcolm, based on the Commission's 2 cent CRS, but which did not include the DWR bond charge, her findings regarding any cost recovery that must be paid, and how much this might be mitigated through the elimination of physical load that is established as a bidding requirement in Ordinance 86-04—the 360 MW rollout.

Specifically, the City and County wishes for confirmation that certain RPS compliant Distributed Generation will be exempted from any exit fee pursuant to existing Commission policy, and utilities could not seek to charge CCA customers for power and capacity from these facilities. Furthermore, the City and County wishes to ascertain whether the Commission will address the requirement of AB117, that as of June 15, 2003 CCAs be allowed the opportunity to administer the energy efficiency Public Goods

Charge funds. San Francisco, as a CCA created by Ordinance 86-04 in May, 2004, is entitled by Public Utilities Code Section 381.1 to an opportunity to administer or directly control the administration of all Energy Efficiency Public Goods Charge funds paid by San Francisco ratepayers, such that these funds may be invested in local energy efficiency programs according to local needs and priorities.

While AB117 requires certain Commission actions for CCAs qualified under ABIIT to proceed, the legislature did not expect the process to establishing CCAs to take as long as it has. The legislation has in effect set a limit to the waiting period in AB117, ordering the Commission to report on the number of customers served by CCAs no later than this coming January 1, 2006, under Public Utilities Code 366.2 (j), which orders that "(t)he commission shall prepare and submit to the Legislature, on or before January 1, 2006, a report regarding the number of community choice aggregations, the number of customers served by community choice aggregations, third party suppliers to community choice aggregations, compliance with this section, and the overall effectiveness of community choice aggregation programs."

Our interpretation of the legislature's intent is that CCAs would be already implemented by this date, and not be delayed, despite full compliance by the City and County of San Francisco and or other California CCAs from doing so until after January 1, 2006. Under our interpretation of the statute, the Commission is bound to facilitate San Francisco's negotiation with ESPs so that it may depart PG&E in 2006.

2.0 Information Required In Or In Addition To The Implementation Plan

The information provided below is a list of the items required to be included in a CCA Implementation Plan, in accordance with Public Utilities Code Section 366.2(c)(3). This Plan addresses each of these items. A cross-reference between the required items and this IP is provided in Appendix A. Some of these items may be referenced in the utility tariff that governs the utility's interactions with the CCA.

- Organization structure of the program
- Ratesetting and other costs to participants
- Disclosure provisions and due process in setting rates and allocating costs
- Methods for entering and terminating agreements
- Rights and responsibilities of program participants, including consumer protection
- Program termination
- Description of Energy Service Providers

- Additional information not required by statute

The City and County is including other additional information in order provide the CPUC a better understanding of the City and County's Implementation Plan. In particular, this Implementation Plan outlines policies and details of its CCA program requirement, in particular a number of bidding requirements adopted in Ordinance 86-04 which will bind the RFP, define the ESP's service irrespective of which ESP ultimately negotiates a successful program resulting in an award of contract by ordinance as required by AB117.

3.0 Implementation Phases

The implementation of the CCA will proceed in five phases:

- A Start-up phase where organizational structure required to implement all aspects of the CCA Program is put into place
- A Program Development phase where the program is developed at a detailed level, and the actual processes for implementation are defined;
- A Procurement phase where the Electric Service Provider for the CCA is selected through competitive procurement
- An Implementation phase where the ESP designs and constructs all of the renewable power generation facilities required under the City and County of San Francisco Ordinance No. 86-04
- An Operations and Maintenance phase where the ESP provides all of the power supply, power generation and other related services required under its contract with the CCA.

It is also possible that renewable power generation infrastructure beyond the levels specifically required under Ordinance 86-04 may be implemented as a follow-on phase of the CCA Program, if the execution of the first set of elements described is successful, and supports the further advancement of the renewables program.

This Draft Implementation Plan describes the San Francisco CCA Program in detail, and sets forth the steps that will be taken to implement it. This draft submitted on April 8, 2005 is preliminary in nature. To cover the broad range of implementation activities, some assumption was required relative to certain program elements. As the program elements are interdependent, subsequent refinement or changes to bases of these assumptions may require restructuring of some of the methods and approaches described herein. In particular, the overall program schedule provided in this draft would require further development based on decisions that would need to be made during the Program Development phase.

4.0 The Process of San Francisco's Aggregation

Exhibit II-1 outlines the Community Choice Aggregation Implementation Steps required by the Public Utilities Code as follows.

**Exhibit II-1
CCA Implementation Steps
Under PUC 336.2**

| ITEM/CODE SECTION | ENTITY |
|--|--------------|
| Adopt rules authorizing community aggregation: 366.2(i)(3); procedures for IOUs to provide CCAs with info: (c) (9); terms and conditions for IOU services to CCAs and customers: (c)(9) | CPUC |
| Request and obtain utility load info: (c)(9) | CCA/IOU |
| Select Energy Service Provider(s) through competitive procurement process | CCA |
| If desired, set up Joint Powers Authority | CCAs |
| Develop Implementation Plan (c)(3) | CCA |
| Adopt Implementation Plan through public process (after public notice) | CCA |
| File Implementation Plan at CPUC (c)(3)and register with CPUC: (c)(14) | CCA |
| Request additional information on Implementation Plan | CPUC |
| Respond to CPUC data requests | CCA |
| Notify local utility of Implementation Plan filing , within 10 days of the filing (c)(6) | CPUC |
| Certify receipt of Implementation Plan within 90 days (c)(7) | CPUC |
| Determine cost recovery charges CCA customers must pay (c)(7) | CPUC |
| Establish post-enrollment period reentry fees paid to IOUs: (c)(11) | CPUC |
| Designate earliest possible date for implementation of CCA Implementation Plan (c)(7) | CPUC |
| Establish terms and rates for all transaction-based costs of notices, billing, metering, collections, customer communications or other services, to be recovered from aggregator or its customers: (c)(17) | CPUC |
| Order for IOUs to send out notices re CCA | CCA requests |

| ITEM/CODE SECTION | ENTITY |
|---|--|
| Implementation Plan; establish fees CCP pays for notices: (c)(13)(B) | (probably in IP); CPUC issues order |
| Determine IOU meter costs (install, maintain, calibrate, read, supply data): (c)(18) | CPUC |
| Register with CPUC: (c)(14) | CCA |
| Send out 2 pre-enrollment notices to customers of CCA: (c)(13) (A) | CCA via IOU (utility bill) pursuant to CPUC order or direct mailings |
| Notify IOU the community aggregation program will begin within 30 days: (c)(15) | CCA |
| Transfer accounts to CCA: (c)(16) | IOU |
| Recover transfer costs, as determined by CPUC, from CCA: (c)(17) | IOU |
| Begin CCA automatic enrollment | CCA |
| “No penalty” period for opting out ends, within 60 days or 2 billing cycles of the date of enrollment (c)(11) | |
| Send out 2 post-enrollment notices to customers: (c)(13)(A) | CCA via IOU (utility bill) and/or direct mailings |
| Submit report to Legislature certifying implementation of cost-recovery mechanisms: (i)(1) and (i)(2) | CPUC |

Notes: CCA = Community Choice Aggregator
IP = Implementation Plan
IOU = Investor Owned Utility
CPUC = California Public Utilities Commission
All Code references are to Sec. 366.2

4.1 San Francisco’s CCA Process History

In September, 1999, the Board of Supervisors unanimously adopted a Resolution by Supervisor Ammiano asking the California legislature to pass a Community Choice Aggregation law.

In November 2001 voters approved an amendment, placed on the ballot by the Board of Supervisors (“H Bond Authority” Ammiano) to the San Francisco Charter San Francisco Charter Section 9.107.8), creating an unlimited, generic revenue bond authority for the Board of Supervisors to issue to finance or refinance the acquisition, construction, installation, equipping, improvement or rehabilitation of equipment or facilities for renewable energy and energy conservation, said issuance to be authorized by an ordinance of the Board. In particular, Mr. Ammiano announced plans to solicit an energy service provider to install 50 Megawatts of solar photovoltaic capacity within the jurisdictional boundaries of San Francisco.

In January, 2002 the San Francisco Public Utilities Commission held a World Solar Industry Workshop, which was followed by significant incremental solar photovoltaic installations at public properties such as the Moscone Center. Subsequently, the Board of Supervisors has adopted an ordinance creating the Generation Solar program, offering residents and businesses assistance with solar photovoltaic purchasing. These programs have been undertaken as pilot projects, in order to prepare city departments for a major, \$ Billion rollout of solar, wind, distributed generation, conservation and energy efficiency technologies at hundreds of locations throughout San Francisco’s 49 square miles.

In March, 2002, San Francisco also adopted Resolution 158-02 directing the City to commit to a greenhouse gas pollution reduction of 20% below 1990 levels by the year 2012.

In December, 2002, San Francisco adopted an Electricity Resource Plan calling for the development of 107 Megawatts of load reduction through electricity load management and efficiency measures, 31 Megawatts of in-City solar energy, 72 Megawatts of small-scale distributed generation such as fuel cells in San Francisco and 150 Megawatts of new wind energy imports by 2012, as well as new natural gas powered generation needed to close over 420 megawatts of power generating facilities at Hunters Point and Potrero power stations.

In September, 2003, the Local Agency Formation Commission (“LAFCO”) accepted a report from R.W. Beck indicating that Community Choice Aggregation may be a feasible method of benefiting consumers and developing renewable energy resources, conservation programs and energy efficiency.

On May 21, 2004 the San Francisco Board of Supervisors unanimously adopted (ordinance 86-04, Ammiano, signed by Mayor Newsom on May 27, 2004), and it went into effect on June 27, 2004. The Energy Independence Ordinance is the governing document ordering preparation of and outlining the structure of this Implementation

Plan, and also ordering City agencies to present a draft Request for Proposals (RFP) for amendment and adoption by the Board of Supervisors. Ordinance 86-04 also ordered City and County departments to request all appropriate billing and load data from PG&E, resulting in the delivery of some incomplete aggregate data.

On December 8, 2004, the Board of Supervisors unanimously approved a resolution (Ammiano, Resolution 757-04), creating a Community Choice Aggregation Citizen's Advisory Task Force "to advise the City on 1) the goals and preparation of a CCA Implementation Plan, 2) the use of Proposition H Bonds to accelerate the use of renewable energy, conservation and energy efficiency in the CCA program, and 3) the requirements in the CCA bid solicitation process, and 4) the evaluation of bids. Furthermore, Resolution 757-04 affirmed that Ordinance 86-04 "called for the development of 107 Megawatts of load reduction through electricity load management and efficiency measures, 31 Megawatts of in-City solar energy, 72 Megawatts of small-scale distributed generation such as fuel cells in San Francisco and 150 megawatts of new wind energy capacity by 2012, as called for by the Electricity Resource Plan adopted by San Francisco in December 2002."

On February 5, 2005, the Board of Supervisors approved a Resolution (Mirkarimi, Resolution 131-05) urging the SFPUC to explore, based on findings of the Local Agency Formation Commission ("LAFCO") reports, implementation of Community Choice Aggregation on Treasure Island.

More recently, in order to supplement ongoing agency efforts, the San Francisco Local Agency Formation Commission, chaired by Supervisor Ross Mirkarimi, has formally requested a Draft Implementation Plan from Paul Fenn, who is the Board of Supervisors' first appointment to the Citizen's Advisory Task Force on Community Choice Aggregation (CCA Task Force). Ordinance 86-04 also ordered City departments to prepare a corresponding draft Request for Proposals within three months of the Board's adoption of this plan. The CCA Task Force will help draft the RFP, review ESP bids and make a recommendation to the Board of Supervisors.

On March 29, 2005 the Board of Supervisors approved a Resolution (Mirkarimi, Resolution TBD) approving a "Protest Letter to the California Public Utilities Commission and the Procurement Review Committee Regarding Approval of Proposed Pacific Gas & Electric Power Purchase Agreements and Energy Efficiency Programs."

4.2 Current Process: Implementation Plan Actions and Requests 2005-6

Having prepared the ground for a successful CCA implementation, the Board of Supervisors now implement a process to switch San Franciscans over to the new,

superior electricity service with either positive or no electric bill impacts for all ratepayer classes at the end of the 120 day opt out period after participating customers transfer from the utility. Accordingly, the Board provides the following processes of its CCA program. This consists of deadlines binding the City and County, the Commission and PG&E, with a series of actions and requests to both the Commission and PG&E, culminating in a binding commitment by the City and County's chosen Electric Service Provider to serve the load according to the Commission's adopted resource adequacy and other statutory and constitutional requirements.

Following the Commission's 90-day certification process pursuant to Public Utilities Code Section 366.2 (c)(7) and any additional information requested by the Commission, the Board of Supervisors shall commence a Request For Proposals (RFP) process for competitive bidding by ESPs using the Commission's findings regarding any cost recovery that must be paid by participating San Franciscans to prevent a shifting of costs as provided for in subdivisions 366.2 (c) (d), (e), and (f).

In order for the Commission to facilitate the Board of Supervisors negotiation with ESPs pursuant to 366(a) of the Public Utilities Code, the City and County of San Francisco requests the Commission to provide, within 90 days of the receipt of this adopted Implementation Plan (which shall be delivered to the Commission the same business day it is adopted), the cost-recovery mechanism that must be paid by participating San Franciscans, pursuant to Section 366.2 (c)(7) of the Public Utilities Code.

San Francisco also requests that the Commission provide the City and County with an earliest possible date to leave Pacific Gas & Electric procurement, in such manner that participating load transfer of customers shall occur 300 days from the date on which this resolution is approved by the Board of Supervisors.

As the Commission's findings regarding any cost recovery that must be paid by customers must be known to the Mayor and Board of Supervisors in order for San Francisco to effectively solicit competitive bids from Electric Service Providers, the Commission is statutorily bound to provide said findings to the City and County in a timely manner as part of its obligation to facilitate negotiation between CCAs and ESPs prior to any binding commitment by the City and County, as required by Public Utilities Code Section 366(a), because the Board of Supervisors must be able to ascertain the net electric bill impacts of an ESP's bid on participating San Francisco ratepayers in order to form a rational comparison of the service being offered, this being impossible without the assignment required by Section 366.2 (c)(7) of the Public Utilities Code.

As the provision of the Commission's findings regarding any cost recovery that must be paid by customers is essential for the City and County to provide an accurate and

transparent explanation of the terms and conditions of the services offered by the CCA program, as required of CCAs by Public Utilities Code Section 366.2(c)(13)(a)(ii) in order to provide ratepayers the opportunity to opt-out of the program, any failure by the Commission to provide such information in a timely manner would violate the customer opt-out notification requirements of that section, and would subvert the authority of the City and County to aggregate the electrical load of interested electricity consumers within its boundaries to reduce transaction costs to consumers, provide consumer protections, and leverage the negotiation of contracts pursuant to 366.2(c)(1) of the Public Utilities Code.

Assuming the Commission's facilitation of the City and County's negotiation with ESPs is forthcoming, the City and County is prepared to commence approval and publication of its RFP as soon as 90 days after the filing of this document, San Francisco's official CCA Implementation Plan, requiring the Commission to notify PG&E within ten (10) days of today, the __ of May, 2005.

Being an emergency ordinance under urgency of PG&E's procurement plan in R. 04-04-003, in accordance with Charter section _____, this Implementation Plan shall go into effect immediately, upon its adoption by the Board of Supervisors. Accordingly, the City and County declares its expectation that the Commission shall notify PG&E, as outlined in Subsection 6, ten days from the Board's adoption of this resolution and the Implementation Plan contained therein, by the Board of Supervisors.

Accordingly, pursuant to Subsection 7, the City and County declares its expectation that the Commission will request information from the Board of Supervisors, certify receipt of this Implementation Plan, and report to the Board of Supervisors its findings regarding any cost recovery that must be paid by customers within 90 days of the passage of this resolution and the Implementation Plan it contains.

Confident that the Commission will respect the rights of San Francisco, and fulfill the requirement of 366(a) of the Public Utilities Code, and shall, following certification of receipt of the Implementation Plan and any additional information requested, within ninety days of the date this resolution is approved, provide the Board of Supervisors with its findings regarding any cost recovery that must be paid by customers of San Francisco Energy Independence to prevent a shifting of costs, as expressly required by Public Utilities Code Section 366.2(c)(7).

San Francisco declares its intent to register the Commission as it prepares its RFP during the 90 day waiting period, and understand that the Commission may require additional information to ensure compliance with basic consumer protection rules and other procedural matters, in accordance with Public Utilities Code Section 366.2(c)(14).

As the City and County anticipates adoption of its RFP as early as ninety (90) days from the adoption of this resolution, and the Implementation Plan it contains, by the Board of Supervisors, the City and County requests the Commission to order PG&E to provide the City and County with all customer billing and load data, including all customer-specific data, time of use metering data, interval meter data, and substation data, including a detailed list of every data field contained in each of the databases.

This request is consistent with Commission policy. In its December 16, 2004 Phase I Community Choice Aggregation decision (D-04-12-046 in R.03-10-003), the Commission agreed that certain types of data are needed for a CCAs to investigate, pursue or implement CCA:

“CCAs must have certain types of information in order to plan their procurement strategies, assess the viability of offering energy services, and to contact customers. Section 366.2(c)(9) anticipates the needs of CCAs for certain types of customer data and information” (p.50)

The Commission also agreed that the data is needed in advance of actual CCA implementation:

“AB 117 is clear in its intent to require the utilities to provide CCAs all customer and usage data that is relevant to CCA operations even before the CCA begins offering service. In addressing the informational needs of CCAs, Section 366. 2 (c) (9) provides that the utilities shall “cooperate” with CCAs that “investigate or pursue” CCA programs. Because a CCA is most likely to “investigate or pursue” CCA programs before it begins offering service, we read the plain language of the statute to mean relevant information must be provided on demand, without distinguishing between a customer who is still with the utility or a customer of the CCA or between the time a CCA is created and the time it provides service. By law, CCAs are entitled to receive certain types of information as long as they are investigating, pursuing or implementing a CCA program” (pp.49-50).

The Commission agreed that the CCA customer notification requirements in AB117 would also depend on access to customer-specific information:

“Section 366.2(c)(13) (A) supports this finding in its requirement that CCAs provide opt-out notifications to prospective customers prior to cut-over. Although Section 366(2) (13)(B) gives the CCAs the option to request utility assistance with the notifications, each CCA must assume ultimate responsibility for the notices. The CCA cannot satisfy this responsibility without access to

customer names and addresses. Thus, if the Legislature had intended for customer information to remain with the utility, it would have not required the CCA to issue the opt-out notices” (p.50).

The Commission provided that AB117 requires CCAs to have access to data that would be considered confidential under Direct Access rules:

“The information the CCAs may need from the utilities may be confidential, for example, (1) basic load and usage data required to estimate energy procurement needs and (2) customer information needed to contact customers and provide services, including name, address, and meter information” (p.47).

The Commission rejected utility arguments that Direct Access confidentiality rules should apply, “*primarily because the statute itself directs the provision of customer information to a CCA*”:

“Moreover, unlike a district attorney investigating criminal activity. The statute permits the CCA to receive such information. Unlike the unwilling subject of a criminal investigation, the customers for whom the CCA seeks information have implicitly agreed to permit the CCA to aggregate their energy requirements and offer service. We believe AB 117 assumes, as we do, that CCAs can be entrusted with confidential customer information. Unlike energy service providers offering direct access, CCAs are government agencies. As long as some basic protections are in place, the risks of providing confidential information to these entities is outweighed by the dictates of the statute and the potential benefits CCA customers would realize only if CCAs have the information they need to make fully informed decisions regarding energy procurement, service requirements and resource planning decisions” (p.51)

As the Commission has determined that the City and County, as a CCA, “can be entrusted” with the data, PG&E should be ordered to provide customer-specific billing data (as opposed to masked load data) to San Francisco in answer to this request:

“In addition to its requirement that utilities provide information to CCAs before and after they initiate operations, AB 117 specifies the types of information the utilities must provide to CCAs. Section 366. 2(c)(9) refers to “appropriate billing and electrical load data, including, but not limited to, data detailing electricity needs and patterns of usage.” The statute specifically refers to “billing” data as distinct from “electrical load data.” We are not aware how aggregated or masked billing data could satisfy the statutory requirement. Again, the plain language of the law means that the CCA is entitled to any and all billing data that is

reasonably useful to the CCA. It also refers to information “detailing” electricity needs and patterns of usage. Use of such specific terms reflect the Legislature’s intent for CCAs to have information that is neither masked nor aggregated, to the extent such information is required by CCAs that would reasonably “investigate, pursue or implement” a CCA program” (p.52).

The Commission then adopted the policy that confidentiality concerns may be addressed by imposing limits on the CCA’s use of the information it receives, by requiring CCA nondisclosure agreements:

“We direct the utilities to provide all relevant usage information, load data and customer information to CCAs. The CCA shall sign nondisclosure agreements for any confidential information that is not masked or aggregated. We will also require that all notices relevant to CCA programs inform customers that the utility may share customer information with the CCA and that the CCA may not use the utility’s information for any purpose other than to facilitate provision of energy services” (p.52)

Accordingly, the City and County hereby agrees that it shall not disclose any confidential customer information to its ESP prior to the termination of the 120 opt-out period, and shall require that all notices relevant to CCA programs inform customers that the utility may share customer information with the City and County, and that the City and County may not use the utility’s information for any purpose other than to facilitate provision of energy services.

Finally, the Commission stated its “intent to enforce the law with respect to its requirement that the utilities ‘cooperate’ with CCAs in the provision of all relevant information, a *term which we interpret broadly*”:

“The utilities may not determine what information is “relevant” to CCA operations as long as the utility is reimbursed for the reasonable costs of providing the information. While we welcome the utilities’ tariff proposals for the secure and cost-effective sharing of information, we will not tolerate utility actions or delays that may affect the provision of information to CCAs or CCA services to customers” (p.53).

Thus, the City and County demands immediate, full, unconditional release of all customer-specific data, as well as all data from every interval and substation meter located within San Francisco’s jurisdictional boundaries, to the City and County, and requests Judge Malcolm to order PG&E to comply with this demand within 30 days of the approval of this resolution, and the Implementation Plan contained herein.

The Commission's Findings of Fact, Conclusions of Law and Orders in D.04-12-046 requires a full disclosure, interpreted broadly, with a CCA nondisclosure agreement to protect confidentiality of customers:

Finding of Fact # 38: "CCAs would 'investigate or pursue' CCA programs prior to offering service and a CCA would need relevant customer and load data in order to conduct a meaningful investigation of CCA programs" (p.62).

Finding of Fact # 39: "A CCA cannot notify customers of its intent to offer electrical service if it does not have access to relevant customer information" (p.62).

Finding of Fact # 40: "In the CCA's effort to satisfy customer notice requirements, tax rolls are not a reasonable substitute for customer information held by utilities partly because property owners would not necessarily be a utility customer of record" (p.63).

Finding of Fact # 41: "Nondisclosure agreements would provide reasonable protections against the disclosure by a CCA of a utility's customer information.

Finding of Fact # 42: "CCAs may need specific customer information in order to market energy services and tailor those services to individual customers or groups of customers" (p.63).

Finding of Fact #43: "CCAs need load data in order to develop cost-effective and reliable energy procurement strategies" (p.63).

Finding of Fact # 44: "Customers would benefit from notification that contact information and usage data may be shared with the CCA and may not be disclosed to others" (p.63).

Conclusion of Law #30: "Section 366.2(c)(9) requires the utilities to provide all relevant information required by CCAs to "investigate, pursue or implement" meaningful programs. This requirement does not permit the utilities to deny CCAs access to relevant customer or load information" (p.67).

Conclusion of Law #31: “Section 366.2(c)(13)(A) requires CCAs to provide customer notice of their intent to provide service, a requirement a CCA cannot satisfy without relevant customer information. Read in conjunction with Section 366.2(c)(9), this requirement presumes that the CCA will have access to certain customer information held by the utility” (pp.67-8).

Conclusion of Law #32: “Section 366.2(c)(9) requires the provision of detailed billing and load data to CCAs that are investigating, pursuing or implementing CCA programs” (p.68).

Conclusion of Law #33: “The utilities should require CCAs to sign nondisclosure agreements when they share confidential information about customers or electricity load and should require a county or city’s chief administrative officer to attest that it is “investigating” or “pursuing” status as a CCA as a precondition to receiving confidential customer information” (p.68).

Conclusion of Law #34: “Notices to prospective CCA customers should inform customers that the utility may share customer information with the CCA and that the information may not be used for any purpose other than to facilitate the provision of energy services to the customer by the CCA” (p.68).

Conclusion of Law #35: “Utility tariffs should provide that the CCA must indemnify utilities from liability for the disclosure of confidential customer information in cases where the utility has take all reasonable precautions to prevent that disclosure” (p.68).

Commission Order #5: “PG&E, SDG&E, and SCE’s proposed tariffs shall include... (12) the offer to provide access to all relevant customer information, billing information, usage and load information, consistent with this order and which shall be provided to the CCA at cost except that those information services already approved in D.03-07-034 shall be provided at no cost to the CCA; (13) a requirement that all confidential utility information shall be provided subject to nondisclosure agreement and a requirement that the chief administrative officer of a city or county attest that the city or county is investigating or pursuing status as a CCA as a precondition of receiving confidential customer information; (14) a requirement that customer notifications about prospective CCA operations inform the customer that customer information may be provided to the CCA subject to nondisclosure for any purpose other than those related to facilitating the CCA’s services; (15) a provision for CCAs to indemnify the utilities from liabilities associated with the CCA’s disclosure of confidential customer

information where the utility has taken all reasonable steps to prevent such disclosure” (pp.70-71).

4.3 SF CCA Request for Proposals

San Francisco declares its intent, upon receipt of an Exit Fee from the Commission within 90 days of the adoption of this resolution, or upon whatever date thereafter that the Commission submits its findings, to conduct a single competitive bidding process for the City and County’s bundled energy service, conforming to the requirements of this Implementation Plan, to registered Electric Service Providers, within 60 days of the date on which the Board of Supervisors receives the Commission’s findings, by publishing the RFP ordered by Ordinance 86-04 and further outlined in this Implementation Plan, in all major Bay Area Newspapers, and also in any state, national and international energy industry trade publications to secure the attention of energy industry sectors for each component of the services and minimum resource portfolio required by the ordinance and this Implementation Plan.

San Francisco declares that it shall allow ESPs ninety days to respond to the publication of its RFP, and shall elect to approve, or not approve, an award of contract to a single Electric Service Provider within 60 days of the deadline for receipt of ESP bids.

Accordingly, if the Commission takes these actions, as needed by the City and County, to facilitate a successful elimination of 650-850 Megawatts of capacity from PG&E’s current electric procurement plan in R.04-04-003, and to minimize the shifting of costs between utilities or their customers and San Francisco ratepayers, consistent with the Commission’s Community Choice Aggregation decision on December 16, 2004, then San Francisco intends to pass an ordinance awarding contract to the City’s chosen ESP 300 days from the date this resolution is approved, pursuant to Public Utilities Code Section 366.2(c)(10(A), and furthermore the City and County declares that this ordinance shall secure the City and County’s chosen ESP’s binding commitment to serve that load as a Load Serving Entity (LSE) in accordance with Conclusions of Law #1 and #4 in and Order # 2 in the Commission’s electric utility procurement framework decision, D.04-01-050, in R.01-10-024 (January 22, 2004, mailed January 26, 2004, pp.192-3 and p.199) .

According to the proposed schedule, the Board of Supervisors requests the Commission, pursuant to Public Utilities Code Section 366.2(c)(13)(B), to approve and order PG&E to insert the City and County’s first CCA notification to San Francisco ratepayers 330 days from the approval of this Implementation Plan, adjusted to any delay in the Commission’s timely response to this Implementation Plan, in its monthly electricity bill to San Francisco electricity ratepayers for the month following said

Commission order by San Francisco pursuant to Public Utilities Code Section 366.2(c)(13)(A).

San Francisco requests the commission to order PG&E to send all four of the notifications required pursuant to subparagraph (A) in the electrical corporation's normally scheduled monthly billing process, and shall pay all reasonable incremental costs PG&E incurs related to the notification or notifications, provided that the electrical corporation, as required by Subsection A, shall fully cooperate with the City and County in determining the feasibility and costs associated with using PG&E's normally scheduled monthly billing process to provide one or more of the notifications required pursuant to subparagraph (A).

One month following award of contract, the City and County shall notify PG&E that the Community Choice service will commence within 30 days, pursuant to 366.2(c)(15) of the Public Utilities Code.

Accordingly, the City and County requests the Commission to designate no later than 330 days from the date this resolution is approved by the Board of Supervisors, pursuant to 366.2(c)(8), as the earliest possible date on which the City and County's CCA program may be implemented.

As Public Utilities Code 366.2(c)(16) requires PG&E to 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 City and County hereby notifies the Commission of the intended date of customer transfer as being 360 days from the adoption of this resolution and the Implementation Plan it contains.

According to this schedule, the Commission should order PG&E to insert San Francisco's second opt-out notification into first monthly electric bill prior to transfer of customers.

Assuming Commission facilitation of the City and County's negotiations with ESPs according to the needs expressed herein, San Francisco declares its intent to transfer customers who did not opt-out of the City's chosen new service 60 days from the date of PG&E's first insertion of San Francisco's notification to customers, approximately 390 days from the approval of this resolution.

According to this schedule, the Commission should order PG&E to insert San Francisco's third opt-out notification into the monthly electric bill following the transfer of participating San Francisco electricity customers, 420 days from the date this resolution is approved.

According to this schedule, the Commission should order PG&E to insert San Francisco's fourth and final notification into its monthly electric bill following the third notification 450 days from the date this resolution, and the Implementation Plan it contains, is approved by the Board of Supervisors.

Upon the day of termination of the opt-out period, the three-year rollout of the City's minimum 360 Megawatt solar, wind, conservation and efficiency facilities by the City and County's chosen ESP shall immediately commence, with the annual rollout schedule outlined in this Implementation Plan beginning on that day and ending in 1,530 days from the date this resolution, and the Implementation Plan it contains, is approved by the Board of Supervisors.

If at the termination of the no cost 120 day opt-out period required by AB117, ten percent or more of the eligible aggregate load has opted out, the 360 MW build requirement shall be proportionately downscaled across each portfolio component of the 360 MW by the actual opt-out amount, rounded to the nearest megawatt. For example, if 10% of the load opts-out, the revised three-year build requirement would be 324 MW of capacity (compared to 360 MW) distributed across the portfolio components as follows:

- 96 MW Energy Efficiency and Conservation in San Francisco
- 93 MW Distributed Generation in San Francisco including minimum 28 MW of Photovoltaics
- 135 MW wind

This downscaling shall be a one time event at the termination of the no cost opt out period only. Subsequent opt outs if any shall not change the MW build requirement. The percentage based RPS requirements on the other hand shall remain unchanged as the result of opt outs because they are by definition a percentage of actual load and therefore scale automatically.

5.0 The Consequences of San Francisco's Aggregation

If the RFP is successful, San Francisco's CCA program will result in the departure of the vast majority of electricity ratepayers living or doing business in City and County jurisdictional boundaries who are now served by Pacific Gas and Electric procurement process in the Commission's electric utility procurement proceeding (now R.04-04-003), with the exception of any load associated with any ratepayers who choose to opt out of the program within 60 days of the transfer of customers to an Electric Service Provider, as per Public Utilities Code Section 366.2(c)(11). The City and County shall not attempt to implement a phase-in of customers on a neighborhood-by-neighborhood basis nor on a customer class-basis, but shall offer its service to any and all PG&E commodity customers who do not elect to continue to be served by Pacific Gas and Electric procurement pursuant to 366.2(a)(2) of the Public Utilities Code.

New Unforecasted Load. In accordance with Resolution 131-05, San Francisco's CCA program will also result in adding the provision of service to any customers on Treasure Island who do not choose to opt out of the program, such that loads not forecasted by the Department of Water Resources nor by PG&E shall be included in this Plan, RFP and ESP contract. Thus, the City and County believes that the Commission's December 16 CCA proceeding decision (D.04-12-046 in R.03-10-003) to exempt the Inland Valley Development Authority (IVDA) from any DWR Contract obligations or bond charges should also apply to this component of the City and County's CCA load. The Commission reasoned:

"Because DWR did not purchase any power on behalf of Norton AFB, ratepayers would not be harmed if IVDA is excluded from the DWR component of the CRS. IVDA's interpretation of AB 117 that the prohibition on cost-shifting should work in both directions is reasonable. Although we do not assume the statute requires this reciprocal treatment, we believe we can lawfully permit an exclusion or exception to the CRS requirements on that basis (D.04-12-046, p.39).

Departing PG&E customer load. The City and County has provided adequate notice for PG&E to avoid procurement on behalf of San Francisco ratepayers beyond May 2006. San Francisco's Community Choice program will not impact any multi-year power contracts by Pacific Gas and Electric, which asserts that in its medium case, PG&E assumed that three percent of its current customers with load under 500 kW will begin to migrate to Community Choice Aggregation in 2006, and the rate of loss to this market will increase by one percent annually, reaching 10 percent in 2013, as recorded and referenced by the Commission in its December 16, 2004 procurement authorization (Decision 04-12-048, p.26). As this decision authorizes contracts now being negotiated and signed by PG&E in its first effort at multi-year power purchase agreements since

AB1890 went into effect, PG&E's power contracts and advice letters to the CPUC and the Procurement Review Committee (PRC). PG&E and the CPUC received San Francisco's Community Choice Implementation Ordinance (Energy Independence Ordinance) on May 27, 2004 when it was signed by Mayor Gavin Newsom. The Energy Independence ordinance ordered this Implementation Plan, and established the basic structure that this Plan must follow, both in transaction structure and in portfolio. With this Implementation Plan now filed in a timely manner to the Commission for an 90 day Exit Fee Assignment pursuant to Section 366.2(c)(7) of the Public Utilities Code, all other impacts of San Francisco's aggregation on electric utility procurement contracts are limited to its annual procurement process, Department of Water resources contracts, and DWR bond charges, as provided for in D.04-12-046.

As provided in Ordinance 86-04, San Francisco's aggregation will result in the installation of at least 150 Megawatts of new wind turbine capacity either within or outside the jurisdiction of San Francisco, 107 Megawatts of conservation and energy efficiency within its jurisdiction, and 104 Megawatts of distributed generation - including a minimum of 31 Megawatts of solar photovoltaic cells - within its jurisdiction. When combined, these facilities will beneficially impact the entire San Francisco Peninsula's grid, eliminating the need for new transmission lines, power plants, offering numerous benefits to PG&E and its remaining customers, for which San Francisco ratepayers should be compensated in the form of a discount on its CRS and or utility implementation and transaction surcharges.

Furthermore, this Implementation Plan establishes a Renewable Portfolio Standard for qualifying bidders of 51% RPS compliant resources by 2017. See Exhibit II -2 "San Francisco RPS."

Exhibit II -2 San Francisco RPS

San Francisco RPS

| contra ct yr # | | expected kwh | EE cumulative capacity savings kw | EE kwh savings 0.25 | pct | net kwh | new build model | buildout kw | output @cf= 0.38 | model buildout RPS | PG&E RPS | contract RPS electricity procurement | |
|-------------------|------|---------------|---|---------------------------|------|---------------|--------------------|----------------|---------------------|--------------------------|-------------|---|-------------|
| | | | | | | | | | | | | Pct | Kwh |
| 1 | 2006 | 5,781,600,000 | 36,000 | 57,240,000 | 1.0% | 5,724,360,000 | 85,000 | 85,000 | 285,307,129 | 5.0% | 15% | 10.0% | 573,346,871 |
| 2 | 2007 | 5,868,324,000 | 72,000 | 114,480,000 | 2.0% | 5,753,844,000 | 85,000 | 170,000 | 570,614,257 | 9.9% | 16% | 6.1% | 350,000,783 |
| 3 | 2008 | 5,956,348,860 | 108,000 | 171,720,000 | 2.9% | 5,784,628,860 | 85,000 | 255,000 | 855,921,386 | 14.9% | 17% | 2.2% | 127,465,520 |
| 4 | 2009 | 6,045,694,093 | 108,000 | 171,720,000 | 2.8% | 5,873,974,093 | | 255,000 | 855,921,386 | 14.6% | 18% | 3.4% | 201,393,951 |
| 5 | 2010 | 6,136,379,504 | 108,000 | 171,720,000 | 2.8% | 5,964,659,504 | 150,000 | 405,000 | 1,359,404,554 | 22.8% | 19% | | |
| 6 | 2011 | 6,228,425,197 | 108,000 | 171,720,000 | 2.8% | 6,056,705,197 | 150,000 | 555,000 | 1,862,887,723 | 30.8% | 20% | | |
| 7 | 2012 | 6,321,851,575 | 108,000 | 171,720,000 | 2.7% | 6,150,131,575 | 75,000 | 630,000 | 2,114,629,307 | 34.4% | 20% | | |
| 8 | 2013 | 6,416,679,348 | 108,000 | 171,720,000 | 2.7% | 6,244,959,348 | 80,000 | 710,000 | 2,383,153,663 | 38.2% | 20% | | |
| 9 | 2014 | 6,512,929,539 | 108,000 | 171,720,000 | 2.6% | 6,341,209,539 | 150,000 | 860,000 | 2,886,636,832 | 45.5% | 20% | | |
| 10 | 2015 | 6,610,623,482 | 108,000 | 171,720,000 | 2.6% | 6,438,903,482 | 150,000 | 1,010,000 | 3,390,120,000 | 52.7% | 20% | | |
| 11 | 2016 | 6,709,782,834 | 108,000 | 171,720,000 | 2.6% | 6,538,062,834 | | 1,010,000 | 3,390,120,000 | 51.9% | 20% | | |
| 12 | 2017 | 6,810,429,576 | 108,000 | 171,720,000 | 2.5% | 6,638,709,576 | | 1,010,000 | 3,390,120,000 | 51.1% | 20% | | |
| 13 | 2018 | 6,912,586,020 | 108,000 | 171,720,000 | 2.5% | 6,740,866,020 | | 1,010,000 | 3,390,120,000 | 50.3% | 20% | | |
| 14 | 2019 | 7,016,274,810 | 108,000 | 171,720,000 | 2.4% | 6,844,554,810 | | 1,010,000 | 3,390,120,000 | 49.5% | 20% | | |
| 15 | 2020 | 7,121,518,933 | 108,000 | 171,720,000 | 2.4% | 6,949,798,933 | | 1,010,000 | 3,390,120,000 | 49.9% | 20% | | |

SF kwh growth rate 1.5% per year

This CCA Implementation now provides that among Electric Service Providers, a bidding requirement shall be added that the 360 Megawatt combination of technologies must be online within three years of the end of the opt-out period.

Just as bridges are financed on tolls, San Francisco's "360" will be repaid on electric bills, with no rate increase, combining the City and County's H Bond Authority approved by voters on November 6, 2001, in conjunction with authorization to negotiate with ESPs pursuant to 366.2(c) of the Public Utilities Code:

"(c) (1) Notwithstanding Section 366, a community choice aggregator is hereby authorized to aggregate the electrical load of interested electricity consumers within its boundaries to reduce transaction costs to consumers, provide consumer protections, and leverage the negotiation of contracts."

As the aggregate demand of the residents, businesses and government electric requires between 650 Megawatts and 850 megawatts at any time, the 360 Megawatt grid upgrade that the City and County builds will deliver environmental and public health benefits unprecedented since perhaps the construction of the City's water and sewer system a century ago, as well as benefits to regional PG&E grid reliability and reducing the need for new transmission lines throughout California. The City formally committed to improving reliability, it is committing its 2001 Proposition H revenue bond authority, pursuant to Section 9.107.8 of the Charter of the City and County of San Francisco, to finance construction of significant local power resources to reduce the over-dependency of San Francisco energy users on centralized gas-fired and nuclear generation, as well as any coal power that the utilities might seek to procure in their ongoing 5 and 10 year power contract negotiations.

In particular, as the principal cause of the state's ongoing Energy Crisis is over-dependence on natural gas combustion for electricity generation, the City and County has established a bidding requirement for any qualifying Electric Service Provider (ESPs) that it shall install 104 MW of distributed generation such as fuel cells, including 31 MW of photovoltaics, and shall remove 107 MW of load through local conservation and efficiency programs, all within its jurisdictional boundaries. In addition to this 211 MW of load removed from within the PG&E substation, the City and County will also require its ESP to build 150 MW of new wind capacity, either along the path of Hetch Hetchy in conjunction with the San Francisco Public Utilities Commission, or at other suitable locations in or around the Greater Bay Area, as determined in the responses of Electric Service Providers to a Request for Proposals, which shall be presented to the Board of Supervisors for amendment and adoption within three months of the adoption

of this IP. In sum, San Francisco will not merely comply with the Renewables Portfolio Standard law, but more than double the schedule established by SB1078 (2002), in addition to far exceeding PG&E's poor performance administering the Public Goods Charge for Energy Efficiency.

CCSF will also have to meet the CPUC's Resource Adequacy Requirements (RAR) associated with serving its customers. These rules also apply to all electricity suppliers and require operating and planning reserves of 15-17% in excess of load. In addition, these requirements will require demonstration of compliance with the rules for the future year's summer peak demand, also under consideration are specific resource adequacy rules for LSEs serving specific resource constrained areas. San Francisco is currently a resource-constrained area therefore any CCSF CCA might have to demonstrate specific in-city resources to serve CCA customers. These rules will have a significant impact CCA resource planning and ultimately generation rates for CCA customers.

Accordingly, the City and County's chosen Electric Service Provider will be required to provide for participating customers' resource adequacy requirements as required by the Commission's December 16, 2004 Decision in its Electric Procurement proceeding. As Energy Efficiency is a core program in San Francisco's Energy Independence ordinance, developing 107 Megawatts of conservation and energy efficiency funds within its ESP's power purchase agreement, the City and County declares its intent to administer, starting in Spring 2006, Public Goods Charge funds for Energy Efficiency as outlined in the Commission's December 16, 2004 Energy Efficiency proceeding, which it estimates to be \$7-10 million per year. San Francisco asks the Commission to limit PG&E's energy efficiency programs so as to make a *pro rata* share these funds available, based on the participation of all residential, commercial, and eligible government electricity customers for local administration to an energy service provider of the City's choosing starting 330 days after the adoption of this resolution, and the Implementation Plan it contains, by the Board of Supervisors.

The Consequences of San Francisco's CCA Program on CPUC Processes are as follows.

5.1. Major Consequences for PG&E 2005 - Procurement Contracts

Pacific Gas and Electric Company announced February 22 2005 that it has entered into a power purchase agreement with Duke Energy Marketing Americas (DEMA) providing PG&E with exclusive rights to dispatch Morro Bay Units 3 and 4, each 325 megawatts, to meet PG&E's capacity and energy needs for the period 2005-2007, adding a new contract to a growing list of agreements that, if approved as early as April, could make

San Francisco ratepayers responsible for new long term power contracts, pursuant to AB57 (Wright, 2002).

Locking customers into the new contracts could create new Exit Fees related to new world electric procurement for all PG&E ratepayers in San Francisco. The Commission is required by AB117 to facilitate San Francisco CCA, but is actually threatening to block CCA implementation by giving away tens of millions of San Francisco energy efficiency dollars to PG&E three years in advance, locking up the funds under PG&E control until 2009. San Francisco declared its intent to depart from PG&E procurement in ordinance 86-04 (May 27, 2005), which contained specific resource requirement data including 107 Megawatts of energy efficiency and conservation measures. Ordinance 86-04 also scheduled preparation of this Implementation Plan and a Request for Proposals three months after its adoption by the Board of Supervisors, so that San Francisco may depart from PG&E procurement in Spring, 2006, switch over service to a new Electric Service Provider, and commence its 360 Megawatt rollout immediately.

Specifically, PG&E has filed an Advice Letter with the California Public Utilities Commission (CPUC) seeking regulatory review and approval of this power purchase agreement with Duke, and requested CPUC approval by April 4, 2005. The purchase is part of PG&E's overall procurement plan to sign power contracts in northern and central California in both the near- and long-term. In addition to entering this agreement, PG&E is currently conducting competitive solicitations for not only near-term supply but also long-term supply and generating capacity, which present San Francisco ratepayers with decades of potential obligation and liability.

Specifically, PG&E contract negotiations present the prospect of billions of dollars in potential stranded costs. The utility announced a settlement agreement with Mirant in January to obtain the rights to dispatch some of the power from Mirant's Contra Costa and Pittsburg Power Plants, as well as the opportunity to complete construction of and operate Contra Costa Unit 8, a 530-megawatt facility. The power purchase agreement will allow PG&E to use Morro Bay Units 3 and 4 to meet load requirements and respond to hourly and daily variations to load as necessary. These transactions, and all PG&E New World Procurement and New World Utility Retained Generation must be limited to a one year basis, beyond the reserve requirements established for all LSEs in D. 04-01-050 of R.01-10-024 on January 22, 2004, in order to minimize overprocurement.

San Francisco applauds the Commission's decision to apply the reasonableness criterion to electric utility procurement this past December 16:

"AB 117 provides that the CRS should include all costs that the utilities reasonably incurred on behalf of ratepayers, which may include costs incurred

after the passage of AB 117 but should not include any costs that were “avoidable” or those that are not attributable to the CCA’s customers (Finding of Fact #20, D.04-12-046, p.60).

While denying a Motion to accelerate the schedule R.03-10-003, Judge Kim Malcolm recognized CCA's concerns that the Commission's regulations not delay CCA implementation relative to multi-year electric utility procurement, and promised to communicate and coordinate with the ALJ in the electric procurement proceeding, such that a “parallel process” between CCA and electric procurement was accepted (March 2, 2004 CCA Workshop). The Commission adopted Judge Malcolm’s verbal commitment to coordinate these proceedings to ensure a place for CCA in D.04-12-046, when the Commission agreed with the need to coordinate and balance electric utility procurement and CCA load departures:

“Utility resource plans will need to balance supply security with enough flexibility to accommodate many market contingencies in addition to those associated with the CCA program, as we have recognized. Because it would ideally recognize and anticipate changing markets and supply sources, resource planning will necessarily be an ongoing, interactive exercise (p. 29).”

With San Francisco now moving to approve its Community Choice Implementation Plan so that its residents and businesses can escape the new Exit Fees from New World Procurement or New World Utility Retained Generation, San Francisco is aware of the significance of the utility contracts, and submits this Implementation Plan with a sense of urgency and alarm that the Commission’s Energy Efficiency proceeding is acting in an unlawful, disorderly manner in relation to a relatively orderly and rational Community Choice proceeding (R.03-10-003) and Electric Procurement proceeding (R.04-04-003).

Secondly, though the Commission’s policies between electric procurement and CCA are relatively developed, PG&E is now rushing to build 2200 Megawatts of new power plants that will impose even higher, multi-decade Exit Fees. With the Commission’s role in approving these contracts now both reduced and delegated to a surrogate (Procurement Review Committees created by D. 04-01-050 in R.01-10-024 on Jan.22, 2004) San Francisco is very concerned at a lack of clear accountability at the Commission in the face of a dangerous breach of laws contained in AB117, and the fact that the City and County must now file its Protest Letter to the PRC in addition to the Commission.

On March 21 PG&E issued an updated Request for Offers (RFO) for long-term electric supply, as part of the resumption of its long-term procurement process which was

temporarily delayed in January. The submission deadline for initial offers is April 27. The RFO solicits offers for both Facility Ownership and Power Purchase alternatives. PG&E officials announced they are seeking to sign contracts for 2,200 megawatts of new power plants in Northern California by 2010. PG&E officials say some of the new plants will be for repowering and others for additional new electrical capacity. PG&E had sought to own at least one, and maybe more, new power plants in its territory and has said it plans to make its own bid to own and operate a 500-to-600-megawatt power plant. PG&E is now looking for up to 1,000 megawatts of new generation by 2008 and another 1,200 megawatts by 2010. Bids can be for plants that supply anywhere from 25 megawatts to 2,200 megawatts.

PG&E's actions present an urgent need for the Commission to coordinate between PG&E and San Francisco's declared load departure schedule, as determined by the Commission. Locking San Francisco customers into the new contracts and power plants will rate base the utility investments for the first time since the Energy Crisis, creating a new round of Exit Fees for all ratepayers. This could block San Francisco and other customers from exercising their legal right to implement CCA, in violation of both AB117 and D.04-12-046.

The Commission wisely acknowledged the issue in D.04-12-046 that utilities in other parts of the states have been accused of blocking CCAs despite the requirement in AB117 that they "cooperate fully" with CCA implementation.

"Los Angeles/Chula Vista argues that SDG&E has already failed to reflect CCA load in its recently-signed power contracts (approved in D. 04-06-011) even though it was aware that the City of Chula Vista had created a CCA in mid-2001. It argues that SDG&E appears to be racing to sign contracts in a manner that will force CCAs to subsidize such purchasing decisions" (p.29).

In D.04-12-046, the Commission agreed fundamentally that it is responsible for coordination of Community Choice Aggregation and Electric Utility Procurement:

"The objective of AB 117 in requiring CCAs to pay a CRS is to protect the utilities and their bundled utility customers from paying for the liabilities incurred on behalf of CCA customers. Our complementary objective is to minimize the CRS (and all utility liabilities that are not required) and promote good resource planning by the utilities" (p. 29).

And furthermore,

“Utility resource plans will need to balance supply security with enough flexibility to accommodate many market contingencies in addition to those associated with the CCA program, as we have recognized. Because it would ideally recognize and anticipate changing markets and supply sources, resource planning will necessarily be an ongoing, interactive exercise” (p.29).

Finally, the Commission agreed that facilitating CCA in the utility procurement process involves forecasting that is not new to either utilities or the Commission:

“We share the parties’ concerns that the utilities must recognize CCA load in their resource planning and should not sign contracts that might create new liabilities for CCA customers and utility customers where available information suggests the power might not be needed. We understand the utilities face a difficult balancing act by assuring adequate and reliable power supplies in amounts that reflect forecasts that are changing constantly. However, the utilities are accustomed to using available information to forecast customer demand and should incorporate CCA load losses into their planning efforts, just as they would include any other forecast variable related to expected changes in supply or demand” (p.29).

As a party to R.03-10-003 that has been investigating, pursuing and now implementing CCA since 1999, the City and County shares the Commission’s concern that PG&E must recognize San Francisco’s load in its resource planning, and should not sign contracts or build power plants that might create new liabilities for any San Francisco ratepayer.

San Francisco declares that this Implementation Plan provides available information suggesting the power for PG&E customers in San Francisco might not be needed. San Francisco also understands the utilities face a balancing act, but also agree with the Commission that this involves a basic gating process not unlike its own procurement process or annual Calendar under which San Francisco has a right to depart from PG&E, not to be delayed by a failure to coordinate between utility and CCA resource planning in R.04-04-003 or an unlawful commitment of San Francisco ratepayer Public Goods Charge funds in R.01-08-028. Indeed, Direct Access has afforded PG&E experience in such planning.

Given that the multi-year programs of the Commission’s electric procurement and energy efficiency proceedings both approve multi-year commitments in June 2005 for implementation in January 2006, and given that AB117 now guarantees CCAs the right to commence transferring customers to their chosen ESPs on January 1, 2006, it is only logical that CCAs now be granted the right to present Implementation Plans for 2006

customer transfer prior to any final authorization of electric procurement contracts or energy efficiency Public Goods Charge funds administration.

5.2 Consequences for Energy Efficiency Programs Under CPUC

A second major impact of San Francisco's Community Choice Aggregation Implementation Plan is that it applies to become an administrator of all funds paid by San Francisco ratepayers in Public Goods Charges for energy efficiency programs, effective June 2005, for implementation in January 1, 2006. This is the same day that the Commission is now preparing to authorize PG&E to commence a Three Year cycle of administering these funds. Therefore, the San Francisco Board of Supervisors adopted a Protest Letter on March 29, 2005 asking the Commission to suspend such activities and offer San Francisco the opportunity to administer these funds starting in 2006.

It is urgent for the California Public Utilities Commission not authorize PG&E to administer Energy Efficiency Public Goods Charge funds after June, 2005, as PG&E's programs face approval in June, 2005. San Francisco shall seek to administer energy efficiency funds effective in June, 2005 pursuant to PUC 381.1:

381.1. (a) No later than July 15, 2003, the commission shall establish policies and procedures by which any party, including, but not limited to, a local entity that establishes a community choice aggregation program, may apply to become administrators for cost-effective energy efficiency and conservation programs established pursuant to Section 381. In determining whether to approve an application to become administrators, the commission shall consider the value of program continuity and planning certainty and the value of allowing competitive opportunities for potentially new administrators. The commission shall weigh the benefits of the party's proposed program to ensure that the program meets the following objectives:

(1) Is consistent with the goals of the existing programs established pursuant to Section 381.

(2) Advances the public interest in maximizing cost-effective electricity savings and related benefits.

(3) Accommodates the need for broader statewide or regional programs.

(b) All audit and reporting requirements established by the commission pursuant to Section 381 and other statutes shall apply to the parties chosen as administrators under this section.

Accordingly, San Francisco declares its intent to apply to become an administrator of any and all funds collected from its ratepayers to fund energy efficiency programs, effective June, 2005, with the City and County declaring its intent initiating administration of programs starting in January, 2006.

Under AB117, even if for some reason the Commission does not elect to make San Francisco the administrator of these funds, whomever the Commission chooses to administer the funds is bound by state law to cooperate with the San Francisco Board of Supervisors:

“If a community choice aggregator is not the administrator of energy efficiency and conservation programs for which its customers are eligible, the commission shall require the administrator of cost-effective energy efficiency and conservation programs to direct a proportional share of its approved energy efficiency program activities for which the community choice aggregator’s customers are eligible, to the community choice aggregator’s territory without regard to customer class. To the extent that energy efficiency and conservation programs are targeted to specific locations to avoid or defer transmission or distribution system upgrades, the targeted expenditures shall continue irrespective of whether the loads in those locations are served by an aggregator or by an electrical corporation. The commission shall also direct the administrator to work with the community choice aggregator, to provide advance information where appropriate about the likely impacts of energy efficiency programs and to accommodate any unique community program needs by placing more, or less, emphasis on particular approved programs to the extent that these special shifts in emphasis in no way diminish the effectiveness of broader statewide or regional programs. If the community choice aggregator proposes energy efficiency programs other than programs already approved for implementation in its territory, it shall do so under established commission policies and procedures. The commission may order an adjustment to the share of energy efficiency program activities directed to a community aggregator’s territory if necessary to ensure an equitable and cost-effective allocation of energy efficiency program activities.”

San Francisco’s 360 MW network will consist of hundreds of generation sites. Based on experience in other industries, the administrative and management costs associated with building at multiple sites should be more than offset by the lower lead time, acquisition time, and permitting time needed to develop sites for distributed renewable facilities than it would take to acquire and permit large fossil generation sites that present health risks to surrounding neighborhoods. The fuel-free capacity and power

that will come online in 2006, 2007 and 2008 will result in reduced power purchases by San Francisco's chosen ESP from wholesale generators, such that an accelerated online schedule will provide a significant profit center for ESPs. This amount is significant, as a 360 MW physical displacement of distribution system peak loads will remove a massive and high cost commodity component (the reserve requirement) of San Francisco ratepayers.

As the Commission is now preparing to approve PG&E's energy efficiency funds program for the period of January 2006 to 2008, it must now deny PG&E authorization to administer any funds paid by San Francisco ratepayers, and to reject the current plan. As a failure of the Commission to answer San Francisco's petition would delay the City and County access to its own ratepayer monies for three years, and San Francisco's build schedule of 107 MW of energy efficiency online by 2009 is an essential component of San Francisco's Implementation Plan, a failure of the Commission to facilitate transactions between San Francisco and Electric Service Providers, in violation of 366.

(a):

The commission shall take actions as needed to facilitate direct transactions between electricity suppliers and end-use customers.

Energy Efficiency is essential to the whole plan because it offers the shortest payback, and on a commodity basis is the "cheapest" component of the 360 MW buildout. Thus, savings from efficiency "pay for" the higher cost elements such as solar photovoltaics. Indeed it is now common industry knowledge that solar photovoltaics and energy efficiency should always be installed at the same time and location in order to make the combined installation pencil out against the price of retail power. Thus, a denial of these funds could serve to undermine the entire CCA Program in violation of Section 381.1(a) and (c) of the Public Utilities Code.

AB117 specifically authorizes Cities and or counties to administer not only electricity as a commodity but also "related services":

"The community choice aggregator may enter into agreements for services to facilitate the sale and purchase of electricity and other related services." (PUC 366.2(c)(1)).

Furthermore, the Commission's decision in D.05-01-055 to reiterate its interpretations of the word "administrator" in Section 381.1 to mean any entity *implementing* an energy efficiency program, causes problems for CCAs such as San Francisco. Ordinance 86-04, which was submitted to the Commission as evidence in June, 2004 in R.03-10-003, provided that San Francisco will be an *administrator*, not an implementer, of these funds,

and that it will solicit an ESP to implement the energy service by its chosen ESP. Indeed, D.05-01-055 appears to recognize the obligation to provide for this opportunity:

“At the same time we recognize that ultimately CCAs are appropriately independent agencies that should have considerable deference to use Section 381 Funds” (D.03-07-034), and have reserved broader issues about CCAs role and discretion for later determination.”

Yet the Commission appears to have falsely interpreted specific deadlines for CCA-related actions in AB117, so as to justify a delay of action that violates state law:

“We are currently establishing the procedures required by AB117. Before CCAs begin serving customers, including obligations of CCAs, recovery of IOU costs, and required reports to the legislature. Once those details are resolved, we may revisit the issue allocating electric energy efficiency PGC funds to CCAs in the context of their role in delivering electricity to their customers.”

In fact, AB117 authorizes CCAs to negotiate with ESPs notwithstanding any action of the Commission, and restricts transfer of customers to three actions. First, it must adopt a Customer Responsibility Surcharge:

“The commission shall not authorize community choice aggregation until it implements a cost-recovery mechanism, consistent with subdivisions (d), (e), and (f), that is applicable to customers that elected to purchase electricity from an alternate provider between February 1, 2001, and January 1, 2003” (PUC 366.2(I)(1).

In CPUC Decision 04-12-046 on December 16, 2004, the Commission implemented a CCA Customer Responsibility Surcharge (CRS) of 2 cents not including the DWR Bond Charge, for the next eighteen (18) months, and specifically invited CCAs to submit Implementation Plans:

Second, the Commission cannot authorize CCA to commence until it has created implementation rules:

“The commission shall not authorize community choice aggregation until it has adopted rules for implementing community choice aggregation” (366.2(I)(3)

In CPUC Decision 04-12-046 it did just that. Indeed, while calling for an open season to start implementing CCA in Phase II of the proceeding and now underway, the

Commission decided that CCAs should not have to wait until Phase II is done before implementing:

“Requiring a CCA to participate in an open season immediately would unreasonably delay initiation of service by CCAs because the Commission will not adopt guidelines for open seasons until Phase II of this proceeding” (Finding of Fact # 49, p.63).

Indeed, in D.04-12-046 the Commission specifically refers to the need to approve existing utility tariffs for CCAs to proceed with Implementation immediately:

“Delaying the implementation of CCA costs until after the resolution of Phase 2 of this proceeding could delay implementation of the CCA program until almost three years after passage of AB 117” (Finding of Fact #31, p.62).”

Indeed, in D.04-12-046 the Commission ordered that utilities must accommodate CCAs proceeding within 60 Days of the December 16 Decision::

“PG&E, SDG&E, and SCE shall, within 60 days of the effective date of this decision, file tariffs that are substantively identical to those in effect for direct access customers and which shall apply in the interim to Community Choice Aggregators (CCAs) prior to the Commission’s approval of final CCA tariffs”. (Order # 2, p.69).

This means that San Francisco may act as of February 16, 2005, which date has already passed. The Commission was very clear in the meaning of this order:

“In all respects, utility tariffs and practices shall permit CCAs to initiate service immediately following the filing of tariffs described in Ordering Paragraph 2” (**Order #9**, p.72).

The third requirement in AB117 before CCA’s may transfer customers is after the Commission has submitted a report on the process of Community Choice Aggregation, including a list of communities providing service, to the legislature:

"The commission shall not authorize community choice aggregation until it submits a report certifying compliance with paragraph (1) to the Senate Energy, Utilities and Communications Committee, or its successor, and the Assembly Committee on Utilities and Commerce, or its successor" PUC 366.2(I)

AB117 says this report must be submitted to the legislature by January 1, 2006 at the very latest, after which (with the CRS and implementation rules) CCAs may commence aggregation:

“The commission shall prepare and submit to the Legislature, on or before January 1, 2006, a report regarding the number of community choice aggregations, the number of customers served by community choice aggregations, third party suppliers to community choice aggregations, compliance with this section, and the overall effectiveness of community choice aggregation programs” (366.2(j)).

D.05-01-055 attempts to justify delaying CCA access to the PGC Energy Efficiency funds based on the legislative deadline for submitting a report to the legislature, the last legal day after which CCAs may proceed irrespective of the Commission: January 1, 2006: the very day that PG&E’s proposed Energy Efficiency Program funds administration is set to start - for the next three years, effectively blocking San Francisco from access to these funds, to which it is entitled either administration or control, since June 2003. Yet the proposed three (3) year PG&E energy efficiency program would commit these funds to PG&E’s program through the end of 2008.

“Stated another way, we may revisit the question of whether CCA customers should be relieved of their responsibility for energy efficiency PGC and procurement surcharges if the CCA elects to take over these functions. Nothing in this decision prevents us from modifying the process for allocating PGC funds to CCAs in the future”

Indeed, its mention of waiting until after PG&E’s 3 year Energy Efficiency program commences to “reconsider” the rights of San Francisco somehow manages to ignore the actual deadline for making the funds available to San Francisco to commence its aggregation, after San Francisco gave adequate notice by adopting Ordinance 86-04 in May, 2004. entitling San Francisco to administer or control said funds effective January 1, 2006.

Decision 05-01-055 on January 27, 2005 that PG&E shall be administrators of all energy efficiency programs within their territories, including in San Francisco, citing among other things the utility’ need to create "integrated resources plans;"

D.05-01-055 does not comply with a direct order of the legislature in AB117. Therefore, San Francisco filed a protest letter (Mirkarimi, Resolution __, March 22, 2005) with the Commission in this regard, demanding its right to apply to administer said funds for

the 2006-2008 cycle, and may take legal action if the Commission fails to acknowledge its rights under AB117 by June 1, 2005.

In its protest letter, the City and County said that “San Francisco, as a CCA, has the need, desire and the statutory authority to create an integrated resources plan, and the energy efficiency funds are a crucial part of such plan, as they are potentially the least expensive resource and therefore the State of California has designated energy efficiency number one in its adopted ‘loading order’ for resource planning. Further, the Protest Letter reads,

“the San Francisco Board of Supervisors hereby urges the Commission not to approve any energy efficiency program administered by PG&E in San Francisco with Public Goods Charge funds, and to immediately provide an avenue for San Francisco, as a CCA, to request and receive all Public Goods Charge energy efficiency funds paid by customers within its jurisdictional boundaries, so that it may make its own decisions on the administration and use of such funds for programs beginning in January, 2006” (Resolution _____, Mirkarimi).

The statute requires the Commission to make the funds available to San Francisco administration on July 15, 2003, not after January 1, 2006:

"No later than July 15, 2003, the commission shall establish policies and procedures by which any party, including, but not limited to, a local entity that establishes a community choice aggregation program, may apply to become administrators for cost-effective energy efficiency and conservation programs established pursuant to Section 381. In determining whether to approve an application to become administrators, the commission shall consider the value of program continuity and planning certainty and the value of allowing competitive opportunities for potentially new administrators" (PUC 381.1(a))

Finally, the Commission must prioritize an orderly CCA/electric procurement process over a flawed Energy Efficiency outcome that appears to confuse legislative deadlines, directly undermines rather than facilitating negotiations between CCAs and ESPs, and directly contravenes the Commission’s adopted policy in D.04-12-06, when the Commission fully recognized the importance of allowing CCAs to proceed with implementing CCA should they so wish:

“However, we do not intend to delay the initiation of service by CCAs while we are considering this matter. In the interim, the utilities must accommodate CCAs that wish to begin delivering power” (p.35).

We refer analysts of D.05-01-055 to the following Findings of Facts, Conclusions of law, and Orders of the Commission in the Community Choice proceeding, R.03-10-003, on December 16, 2005:

Finding of Fact # 9. Delaying the effectiveness of CCA tariffs until after the close of Phase 2 in this proceeding would unreasonably delay the implementation of the CCA program. (P.59)

Finding of Fact # 31: Delaying the implementation of CCA costs until after the resolution of Phase 2 of this proceeding could delay implementation of the CCA program until almost three years after passage of AB 117.

Conclusion of Law #3: Each utility should be permitted to establish balancing accounts for implementation costs incurred prior to the implementation of its next general rate case. Those balancing accounts should be eliminated once the Commission has authorized a related revenue requirement in that general rate case”

Conclusion of Law #7: “The utilities should be ordered to propose final tariffs for recovery of transactions costs from ratepayers within 60 days of the effective date of this order for consideration in Phase 2 of this proceeding” (p.64).

Conclusion of Law #6: “The utilities should be ordered to apply direct access tariffs for CCA transactions until the Commission has approved final CCA tariffs in this proceeding” (p.64).

Conclusion of law #23: “The utilities should establish balancing accounts for CRS costs and revenues and reconcile actual costs and revenues in the proceedings addressing the CRS for direct access customers, unless the Commission directs review of these costs and revenues in a different proceeding” (p.66).

Conclusion of Law #25: “In the interim, the utilities should be ordered to apply the rates and cost recovery provisions of direct access tariffs to CCAs that begin operations prior to the Commission’s approval of final CCA tariffs” (p.66).

Conclusion of Law #41: “CCAs may initiate service prior to the Commission’s adoption of open season guidelines” (p.69).

Order #2: “PG&E, SDG&E, and SCE shall, within 60 days of the effective date of this decision, file tariffs that are substantively identical to those in effect for direct access customers and which shall apply in the interim to Community Choice Aggregators (CCAs) prior to the Commission’s approval of final CCA tariffs”

(p.69).

Order # 9: “In all respects, utility tariffs and practices shall permit CCAs to initiate service immediately following the filing of tariffs described in Ordering Paragraph 2 (Order #2, directly above)” (p.72).

5.3 Consequences for Physical In-City Load Reliability Impacts of San Francisco’s Community Choice Aggregation Implementation Plan

San Francisco’s need for capacity and power across the grid will be dramatically impacted by the 360 MW buildout. In just three years, San Francisco will not only far exceed the RPS law, but will provide new green Megawatts and Negawatts to remove a significant portion of the community’s aggregate substation and transmission load.

San Francisco will use H Bonds and available CPUC and California Energy Commission (CEC) subsidies to finance the following required components of any qualifying ESP’s Power Purchase Agreement Portfolio (PPAP).

5.3.1 107 MW Efficiency and Conservation Megawatt 3 Year Build Schedule

San Francisco expects the following load reductions to be achieved within San Francisco’s jurisdictional boundaries by its chosen Electric Service Provider within its jurisdictional boundaries:

2006 29 MW Load Removed
 2007 34 MW Load Removed
 2008 44 MW Load Removed
 2009 TOTAL 107 MW Load Removed, Option for More

5.3.2 31 MW Solar Photovoltaic and Distributed Generation 3 Year Build Schedule

San Francisco expects the following afternoon peak solar photovoltaic capacity to be installed within its jurisdictional boundaries over the period:

2006 0MW
 2007 10 MW Online
 2008 21 MW Online
 2009 TOTAL 31 MW ONLINE, Option of More

5.3.3 72 Megawatts of Distributed Generation (Renewable, Net 75% Capacity Factor)

Depending on the availability of CEC and CPUC subsidies, San Francisco will issue H Bonds to build Five or fewer 15 MW or more Renewable or Hydrogen or Hybrid Powered Distributed Generation Facilities (Assuming 20% Admin).

2006 15 MW
2007 40 MW
2008 17 MW
2009 Total 72 MW online with option for more

5.4 Consequences for In-City or Out-of-City Physical Load Reliability Impacts : 150 MW Wind Farm (Hetch Hetchy Capacity Factor 30%)

San Francisco expects the following capacity to be installed On Hetch Hetchy property or other properties in conjunction with the City's Chosen ESP or another entity, as determined by the outcome of its Request for Proposals to ESPs, for the period 2006-2008:

2006 0 MW
2007 150 MW
2008 TOTAL OF 150 MW, Option of More

5.5 Consequences for Ratepayer Risk

There are two categories of ratepayer risk: the CCA customer risks, and the bundled service ratepayer risks. The Commission shall act in a manner that prevents shifting of costs not specifically associated with a CCA onto bundled service customers, However, it also makes clear that it is responsible for minimizing shifting of costs onto CCA customers as well”

Observing that PUC Section 366.1(d)(1) states the Legislature's intent “to prevent any shifting of recoverable costs between customers,” not merely costs shifted onto bundled service customers but also cost shifted onto CCA customers, and that PUC Section 366.2(f)(2) directs the Commission to set a CRS based on “costs attributable to the customer,” the Commission ordered that utilities may be forced to assume costs if they were avoidable or unreasonable:

“**Order #20.** AB 117 provides that the CRS should include all costs that the utilities reasonably incurred on behalf of ratepayers, which may include costs

incurred after the passage of AB 117 but should not include any costs that were “avoidable” or those that are not attributable to the CCA’s customers” (p.60).

Specifically, the Commission made clear that certain loads may be excluded by the Commission, as it did with the Inland Valley Development Agency in the December 16, 2004 Decision:

“Because DWR did not purchase any power on behalf of Norton AFB, ratepayers would not be harmed if IVDA is excluded from the DWR component of the CRS. IVDA’s interpretation of AB 117 that the prohibition on cost-shifting should work in both directions is reasonable. Although we do not assume the statute requires this reciprocal treatment, we believe we can lawfully permit an exclusion or exception to the CRS requirements on that basis” (p.39).

San Francisco believes that the timely adoption of its Energy Independence Ordinance, (86-04, signed by Mayor Newsom on May 27, 2005), which provided specific information about San Francisco’s CCA program (and submitted as evidence to the CPUC in Phase I of R.03-10-003) renders any New World Procurement or New World Retained Generation by PG&E since that date to have been avoidable under D.04-12-046, and to be unreasonably incurred, meaning that participating San Francisco ratepayers are immune from any CRS obligations related to such contracts or investments, and are therefore are not a risk to San Francisco ratepayers..

6. Consequences for Electric Service Provider Risk

Energy Independence Ordinance Shifts Contract Failure Risks from CCA and CCA Ratepayer to ESP. San Francisco’s CCA Ordinance 86-04 requires that qualifying ESP bids must include the costs associated with a potential contract failure. Under AB117, this risk may be born by either a CCA or an ESP:

“If a customer of an electric service provider or a community choice aggregator is involuntarily returned to service provided by an electrical corporation, any reentry fee imposed on that customer that the commission deems is necessary to avoid imposing costs on other customers of the electric corporation shall be the obligation of the electric service provider or a community choice aggregator, except in the case of a customer returned due to default in payment or other contractual obligations or because the customer’s contract has expired. As a condition of its registration, an electric service provider or a community choice aggregator shall post a bond or demonstrate insurance sufficient to cover those reentry fees. In the event that an electric service provider becomes insolvent and

is unable to discharge its obligation to pay reentry fees, the fees shall be allocated to the returning customers” (PUC 394.25(e)).

San Francisco declares its intent, as it has already declared in Ordinance 86-04, that under the bidding requirements of its Implementation Plan and Request for Proposals, the ESP, not the City and County, shall assume all risks of its competitively bid and contracted-for rates, including all costs of the bundled product:

“Appropriate contract and bid requirements, including...III. A requirement that bids include proposals for rate design, with all costs and profits associated with providing the various components of its proposed service package, including the costs of designing, building, operating and maintaining all renewable energy, conservation and energy efficiency installations, as well as any capital, insurance and other costs associated with fulfilling the commitments made in its bid” (ordinance 86-04, May 27, 2004, p. 6).

Furthermore, the ordinance requires that under the bidding requirements of its Request for Proposals, the ESP, not the City and County, shall assume all risks associated with an involuntary return of San Francisco CCA customers to PG&E:

“The RFP shall require that qualifying Electric Service Provider post a bond or demonstrate insurance sufficient to cover the cost of reentry fees in the event that customers are involuntarily returned to service provided by PG&E, pursuant to section 394.25(e) of the Public Utilities Code, and shall bid an insured electricity rate schedule, similar in structure to that appearing on monthly PG&E bills, which conforms to the City’s rate-setting mechanism as adopted in its Implementation Plan, pursuant to 366.2(c)(3) of the public Utilities Code.” (Ordinance 86-04, p.9).

5.7 Consequences for Independent System Operator (ISO) Reliability

5.7.1 Substation Load Dropped (minus growth) after 3 years

San Francisco’s Implementation Plan will reduce 211 Megawatts of peak load at the PG&E substation on the South Peninsula, meaning physical load will disappear on the ISO’s transmission grid, making this capacity available to South Peninsula residents, businesses and institutions, and eliminating the need for future transmission upgrades that all South Peninsula communities strongly oppose. The Ordinance 86-04 requires that its Electric Service Provider will add within three years after the opt-out period required by Public Utilities Code 366.2(a) and (c)(11) and (c) (13) the following

capacity additions and load reductions at the electrical distribution system level described in the previous sections:

- Section 5.3.1 “107 MW Efficiency and Conservation Megawatt 3 Year Build Schedule”
- Section 5.3.2 “31 MW Solar Photovoltaic and Distributed Generation 3 Year Build Schedule”
- Section 5.3.3 “72 Megawatts of Distributed Generation (Renewable, Net 75% Capacity Factor)”

5.7.2 Hetch Hetchy 150 MW Wind Farm (Capacity Factor 20-30%)

Hetch Hetchy would benefit disproportionately from an addition of wind capacity physically close to its hydro resource in order to reduce need for hydro throughputs and develop RPS compliant renewable energy resources along its transmission asset.

San Francisco’s Implementation Plan will add 150 Megawatts of capacity on or within reach of Hetch Hetchy properties, and shall require transmission capacity on the existing Hetch Hetchy property, shall require access to ISO transmission capacity, and shall require transmission through PG&E’s distribution system to Participating S.F. Energy Independence ratepayers as a built-in component of our locally adopted Renewable Resource Requirement in Ordinance 86-04.

The capacity to be installed on Hetch Hetchy is per Section 5.4 “Consequences for In-City or Out-of-City Physical Load Reliability Impacts : 150 MW Wind Farm (Hetch Hetchy Capacity Factor 30%)”

The City and County remains interested in acquisition of PG&E’s distribution system. In the event that voters approve an initiative creating a financing authority at a future date to pay for such an acquisition, the City and County will transition from CCA service to wholesale service as a municipal utility or other public power entity, but will also honor all contracts and bond covenants with its chosen Electric Service Provider and other parties. All renewable energy and conservation facilities financed by the H Bond authority shall revert to City ownership at the retirement of the H Bonds that financed the facilities.

III. LEGAL AUTHORITY SUMMARY

1.0 San Francisco Community Choice Aggregation Program Authority

The legal authority for the City and County of San Francisco to implement a Community Choice Aggregation Program (CCA) is provided in the following statutes and ordinances:

| SECTION | ITEM | DATE |
|---------|---|--------------------|
| 1.1 | San Francisco voter approval of Proposition H, Charter Section 9.107.8 | November 6, 2001 |
| 1.2 | California Assembly Bill 117 | September 24, 2002 |
| 1.3 | City and County of San Francisco Ordinance No. 86-04 (Provided in Attachment 1) | May 18, 2004 |
| 1.4 | Resolution 757-04 creating a Citizen's Advisory Task Force regarding the design and implementation of a Community Choice Aggregation Program in accordance with Ordinance 86-04 | December 8, 2004 |
| 1.5 | California Public Utilities Commission of the State of California Decision 04-12-046 | December 16, 2004 |

1.1 Proposition H, San Francisco Charter Section 9.107.8

In the General Municipal Election of November 6, 2001, San Francisco voters approved Proposition H, authorizing the Board of Supervisors to provide for the issuance of Proposition H revenue bonds, without further voter approval, for the purpose of financing or refinancing the acquisition, construction, installation, equipping, improvement or rehabilitation of equipment or facilities for renewable energy and energy conservation.

1.2 California Assembly Bill 117

California Assembly Bill 117 (AB 117) authorizes the creation of Community Choice Aggregation (CCA), describes essential CCA program elements, requires the state's utilities to provide certain services, and establishes methods to protect existing utility

customers from liabilities that they might otherwise incur when a portion of the utility's customers transfer their energy services to a CCA.

AB 117 provides that a CCA must develop an implementation plan detailing the processes and consequences of aggregation. The implementation plan, and any subsequent changes to it, shall be considered and adopted at a duly noticed public hearing. In order to determine the cost-recovery mechanism to be imposed on the CCA that shall be paid by the CCA customers to prevent shifting of costs, the CCA shall file the Implementation Plan with the California Public Utilities Commission, and provide any other information requested by the Commission that the Commission determines is necessary to develop the cost-recovery mechanism.

A CCA establishing electrical load aggregation is also required to prepare a statement of intent with the implementation plan.

1.3 San Francisco Ordinance No. 86-04

San Francisco Ordinance No. 86-04 established a Community Choice Aggregation Program in accordance with California Public Utilities Code §§ 218.3, 331.1, 366, 366.2, 381.1, and 394.25, and required the City and County of San Francisco's Community Choice Aggregation Program to exceed the goals for energy efficiency, renewable energy, peak shaving and load management provided for in the City's Electricity Resource Plan, adopted in December of 2002.

The San Francisco Electricity Resource Plan of December 2002 called for the development by 2012 of:

| | |
|--|--------|
| Load Reduction Through Electricity Load Management And Efficiency Measures | 107 MW |
| In-City Solar Energy | 31 MW |
| Small Scale Distributed Generation | 72 MW |
| New Wind Energy | 150 MW |

In March of 2002, San Francisco adopted Resolution 158-02 directing the city to commit to a greenhouse gas pollution reduction of 20% below 1990 levels by the year 2012.

San Francisco Ordinance No. 86-04 provides that the Board of Supervisors may adopt or amend a Draft Implementation Plan at a duly noticed public hearing by ordinance. The

Ordinance sets forth a number of elements (consistent with AB 117's requirements for CCA Implementation Plans) that must be addressed in the Implementation Plan.

This Implementation Plan has been prepared in full compliance with the requirements set forth in the ordinance. A matrix of the ordinance requirements noting the section of the plan in which they are addressed is provided in Appendix C. The proposed statutory compliant Implementation Plan is provided as Appendix A.

1.4 San Francisco Resolution 757-04 Citizen's Advisory Task Force

Resolution 757-04 of December 8, 2004 authorized the formation of a seven member Community Choice Aggregation Citizen's Advisory Task Force in accordance with Ordinance 86-04 to advise the City on 1) the goals and preparation of a CCA Implementation Plan, 2) the use of Proposition H Bonds to accelerate the use of renewable energy, conservation and energy efficiency in the CCA program, 3) the requirements of the CCA bid solicitation process, and 4) the evaluation of bids.

1.5 California Public Utilities Commission Decision 04-12-046

As a part of Rulemaking 03-10-003, the Public Utilities Commission of the State of California issued Decision 04-12-046 of December 16, 2004, which adopted the following:

- Department of Water Resources' (DWR) methodology for estimating the cost recovery surcharge (CRS), which will allow the utilities to recover from CCAs the costs of DWR bonds and contracts, utility power procurement contracts and other items in a way that remaining bundled utility customers are indifferent to the CCA program
- A temporary CRS in the amount of \$.020/kWh, which will be trued up in 18 months or sooner, if final utility estimates of CRS are 30% lower or higher than \$.020/kWh, and thereafter will be trued up annually
- Principles for setting prices for utility services offered to CCAs
- Ratemaking and cost allocation principles for utility services offered to CCAs, implementation costs and the CRS
- A method to allocate amounts related to the subsidy for baseline customers

- Requirements for and conditions under which CCAs can acquire customer information from utilities needed to manage energy procurement by CCAs
- Application of AB 117 as it relates to CCA program phase-ins, boundary metering and the use of CCA-specific load profiles

IV. PROGRAM SCOPE

1.0 Overall Program Schedule

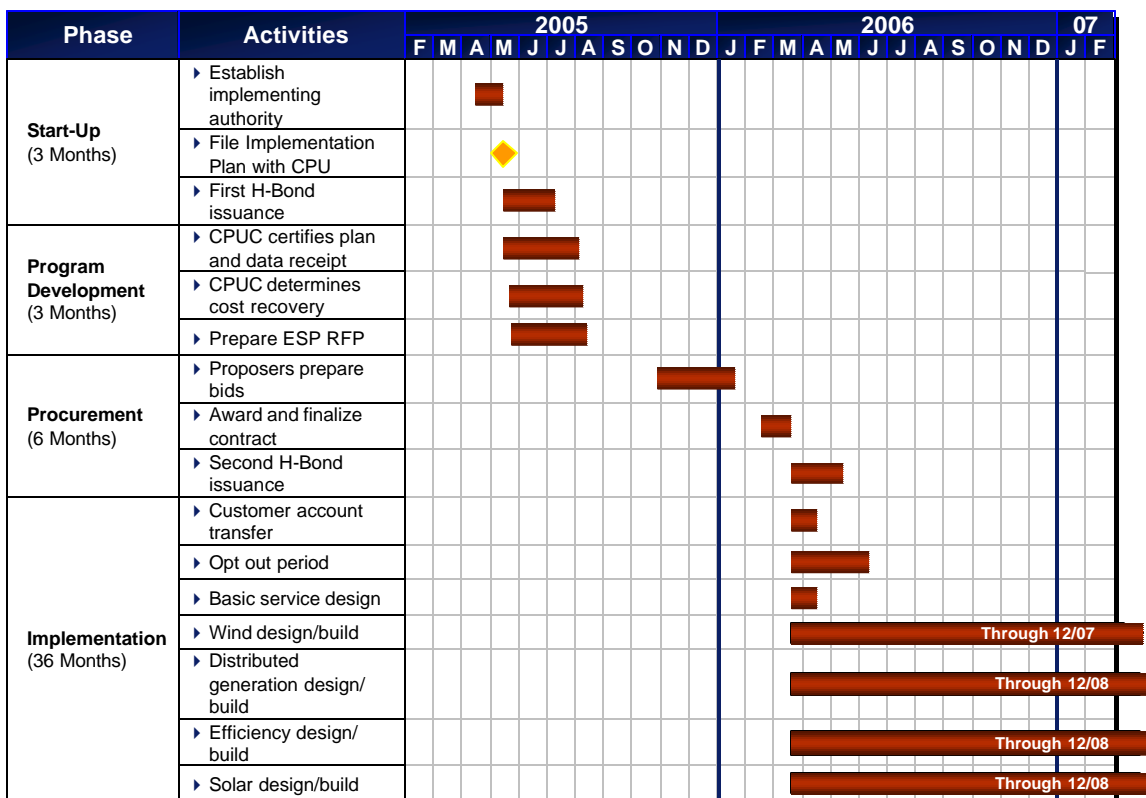
The CCA Program is defined in five major phases:

- Start-Up
- Program Development
- Procurement
- Implementation
- Operations and Maintenance

These phases are subsequently addressed in detail in Section V of this Implementation Plan.

Exhibit IV-1 summarizes the timeline and major activities for the first four program phases. The length of the Operations and Maintenance phase is an open item that needs to be decided as part of the Program Basis Report development process covered in Chapter V, Section 2.3 “Program Basis Report.” The expected full contract duration could range from 7 to 15 years. Appendix B provides a more detailed view of the overall schedule.

CCA Implementation Schedule Summary



Note: Full Operational Phase not shown



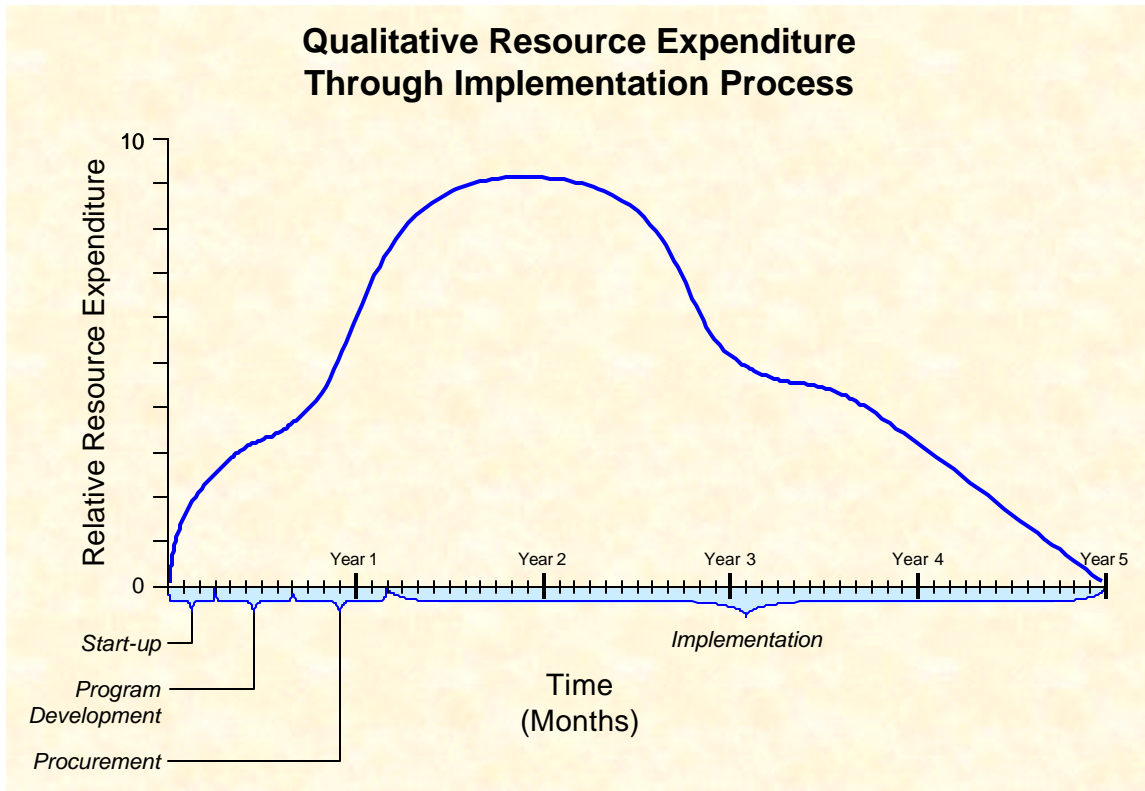
Exhibit IV-1

Add relevant CPUC related dates to the Implementation Plan Schedule.

2.0 Qualitative Program Expenditure Profile

As illustrated in Exhibit IV-3, the expected expenditures vary substantially throughout the program implementation phases. The expenditures represented in this exhibit relate to the start-up of the overall CCA program and the development of the renewable

and energy efficiency elements. The purpose of the exhibit is simply to provide a qualitative picture of the relative expenditure by phase.

Exhibit IV-3

During the start-up, program definition and procurement phases, the need for dedicated implementing entity staff and specialty expertise drives expenditures. As the program moves into the ESP implementation phase, the capital expenditures on renewable technology and the ESP's own design and build resources drive expenditures. The implementing entity will need to perform a detailed cash flow analysis in conjunction with the H-Bond underwriter to appropriately match the bond revenues to the expenditure and repayment profiles.

3.0 Program Funding and Budget

The other major economic findings of the economics analysis (of the SFPUC plan) are as follows:

- The long-term economic value of the CCA will depend upon the superior contracting abilities of the supplier chosen by the CCA;
- The ability of the CCA to bond-finance wind resource development or similarly low-cost renewable energy projects is vital;
- And CCA construction of base-load natural gas facilities is likely to result in uneconomic results based on more competitive base-load alternatives.

Of particular interest are the results of wind power investment for CCSF. Such investment appears economic only if the City can, via contracting, “shape” the wind-power delivery to replace wholesale market purchases of peaking power. However this investment in wind power will have to be much larger in MW output than is consumed by the CCA during peaking periods. This is a result of the assumption that the CCA will have to “re-buy” the shaped wind power for peaking needs in tradition 6X16 blocks of purchased power – a considerable portion of which is surplus to the CCA needs and is sold on the spot market. This wind project scenario, which assumes a City growth rate in electricity consumption of 1.65% per year, promises the greatest economic benefits of any of the scenarios examined in [by the SFPUC].

SFPUC/SFE analyzed a scenario where a substantial amount of baseload renewable power would be purchased under contract as well as a significant amount of peak-load power. “In both cases the current market price referents established by the CPUC were used to price this power. The economic results of this scenario are not positive. This is due to contracting for peak renewable power – assumed to be solar – displacing competitively priced wind power; and contracting for baseload renewable power – likely to be biomass– displacing less expensive traditional market-based supply.

3.1 H Bonds and Public Goods Charge Funds & Other Funding

This Implementation Plan establishes an aggressive buildout of new solar, distributed generation, energy efficiency and conservation technologies throughout the City, and gives a full explanation of San Francisco’s renewable energy, conservation and efficiency resource requirement as already adopted by the Board of Supervisors and Mayor. This Implementation Plan outlines the City and County’s plans concerning administration of Public Goods Charge funds for local energy efficiency programs, and protests any approval of Pacific Gas and Electric’s proposed energy efficiency programs using funds paid by San Francisco ratepayers, in violation of AB117. The goal of this additional information is to provide enough specificity of notice to the Commission to minimize the shifting of costs between CCA customers and bundled service customers, as adopted by the Commission in R.03-10-003 (D.04-12-046). In particular this Implementation specifies a particular model of CCA based on the use of a generic

municipal revenue bond authority, the Prop H charter authority (H Bonds) to finance a three year Phase I rollout of 360 Megawatts of solar, wind distributed generation, conservation and energy efficiency.

The City and County remains interested in acquisition of PG&E's distribution system. In the event that voters approve an initiative creating a financing authority at a future date to pay for such an acquisition, the City and County will transition from CCA service to wholesale service as a municipal utility or other public power entity, but will also honor all contracts and bond covenants with its chosen Electric Service Provider and other parties. All renewable energy and conservation facilities financed by the H Bond authority shall revert to City ownership at the retirement of the H Bonds that financed the facilities.

3.2 CCA Contract Funding

For the renewable power generation infrastructure component of the CCA Program, as provided by Ordinance 86-04, the Proposition H bonds may be used to finance the design and construction. The H bonds will be repaid through the rates developed by the ESP in response to the RFP.

Ordinance 86-04 provides the following relative to the use of H bonds:

Section 3(A)(9) "Appropriate contract and bid requirements (for the ESP), including:

- I. (omitted)
- II. Recommended contract periods designed to optimize meeting or exceeding Electricity Resource Plan goals and to provide a reasonable repayment schedule for debt."

Section 3(B) "With the assistance of City finance staff, the Departments shall determine how Proposition H Bonds may be used to augment CCA by providing financing for renewable energy and conservation projects, including a bond repayment schedule based on anticipated revenues collected from monthly bills and other sources."

Section 4(D) "The RFP shall require that bids by prospective Electric Service Providers shall include a proposed rate design, with all costs and profits associated with providing the various components of its proposed service package, including the costs of designing, building, operating and maintaining all renewable energy, conservation and energy installations, as well as any

capital, insurance and other costs associated with fulfilling the commitments made in the bid, to be reflected in a per kilowatt hour rate schedule that is comparable to PG&E's rate schedule and consistent with the resource portfolio requirements and rate setting mechanisms contained in the City's adopted Implementation Plan."

The CCSF Ordinance requires the examination of Proposition H Bonds as a vehicle to augment CCA by providing for financing of renewable energy and conservation projects. Prop H bonds could offer lower cost debt than would be available to a commercial power plant developer. This cost advantage may be magnified if wholesale natural gas prices remain high or go higher. As long as gas prices are enough that electricity produced by gas-fired power plants is more expensive than electricity produced at wind plants, for example, wind plants will be able to sell the electricity at the marginal price of power – the gas-fired price. In those circumstances, cost-based wind power generated from municipally financed facilities may be attractive enough to outweigh the risks of long-term power plant ownership or leasing. The other attractive aspect of wind plant ownership, or long-term leasing, is the lack of fuel risk, both on price and physical delivery.

The contract will be structured to manage the flow of H bond funds throughout the design and construction phase to ensure that the cash flow is 'neutral' for the City and the ESP. Invoicing and payment structures will be implemented to measure progress and ensure that the ESP is not paid in advance of the completion of any elements of their work. The contract will also provide clear prompt payment mechanisms to ensure that the ESP does not have to build unnecessary carrying costs into its bid prices.

The ESP will be required to provide financial assurances for the design, construction and warranty periods for the renewable power generation infrastructure components and any efficiency installations. The RFP will contain the requirements for these financial assurances, which may include Performance and Payment Bonds, Letters of Credit, Corporate Guarantees, etc. or combinations thereof, as approved by the City Attorney.

The ESP contract will also include the requirement that the ESP bear the responsibility for contract failure, and also provide bonds or insurance to ensure that all involuntary reentry fees are paid by the ESP, and do not have any impact on ratepayers. Ordinance 86-04 provides:

Section 4(E) "The RFP shall require that qualifying Electric Service Providers post a bond or demonstrate insurance sufficient to cover the cost of reentry fees in the event that customers are involuntarily returned to service provided by PG&E,

pursuant to section 394.25(e) of the Public Utilities Code, and shall bid an insured electricity rate schedule, similar in structure to that appearing on monthly PG&E bills, which conforms to the City's rate setting mechanism as adopted in its Implementation Plan, pursuant to 366.2.(c)(3) of the Public Utilities Code.

3.3 CCA Implementation and Board-Based Transaction Funding

In Ordinance 86-04, the Board of Supervisors provided that H Bonds shall be made available to the City and County's chosen ESP to augment the renewable energy portion of its contract.

The Board of Supervisors has created a resolution to authorize the establishment of a method for the San Francisco Board of Supervisors to make declarations of official intent in order to permit San Francisco to reimburse itself for those capital expenditures associated with the purchase of renewable energy, conservation and energy efficiency technologies from proceeds of future taxable or tax-exempt borrowings in accordance with the Treasury Department's reimbursement regulations.

The resolution reads as follows:

"The Board authorizes, designates and directs the City Treasurer to act on behalf of the City in declaring the City's official intent from time to time to reimburse capital expenditures of the City with proceeds of future taxable or tax-exempt borrowings. The declaration of official intent shall (a) state that the City shall finance construction of a green power network consisting of 104 Megawatts of new distributed generation capacity such as fuel cells, including a minimum of 31 Megawatts of solar photovoltaic cells, as well as 107 Megawatts of conservation measures, as well as 150 Megawatts of new wind generation capacity (the "Project"); (b) state that the City intends to issue tax-exempt or taxable debt (the "Debt") to finance the costs of the Project; (c) state that the City will pay certain capital expenditures in connection with the Project prior to the issuance of the Debt; (d) state that the City may use temporary funds which are or will be available on a short-term basis to pay for capital expenditures related to the Project; (e) state that the City reasonably expects that it will reimburse itself for the use of such funds with proceeds of Debt to be issued by the City to finance the costs of the Project within 18 months after the date of the original expenditure or within 18 months after the date the Project is placed in service or abandoned, whichever is later (but in no event more than 3 years after the date of the original expenditure. Each such declaration of official intent shall be noted prior to or within 60 days of the first expenditure on such Project (or such later time as may be permitted by the Reimbursement Regulations) with the Clerk of

the Board, who is hereby authorized and directed to maintain a record of all declarations of official intent, the capital expenditures to be covered by such declaration and the allocations of Debt proceeds to reimbursement for such capital expenditures. The City Treasurer, in consultation with the City's designated bond counsel, is further authorized and directed to take all necessary and desired actions to implement this procedure for declaration of official intent."

3.4 107 MW Efficiency and Conservation Megawatt 3 Year Build Schedule

San Francisco declares its intent to solicit an apply to administer the following PGC Energy Efficiency funds on the 2006-8 cycle:

2006 \$7 Million PGC EE Funds
2007 \$7 Million PGC EE Funds
2008 \$7 Million PGC Funds

These funds will be supplemented by issuance of H Bonds to finance the 107 MW commitment:

2006 \$20 Million H Bonds Conservation
2007 \$30 Million H Bonds Conservation
2008 \$30 Million H Bonds Conservation

3.3 31 MW Solar Photovoltaic and Distributed Generation 3 Year Build Schedule

San Francisco will seek all available CPUC and CEC subsidies to support its 3 Year 31 MW Solar Photovoltaic Network Installation:

2006 \$10 Million
2007 \$10 Million
2008 \$10 Million

Depending on the availability of CEC and CPUC Subsidies, San Francisco will issue H Bonds, to be determined by the requirements of its chosen ESP, for its 31 MW Solar Photovoltaic Network for the period 2006-2008:

2006 \$7 Million
2007 \$40 Million
2008 \$40 Million

3.4 150 MW Wind Farm (Hetch Hetchy Capacity Factor 30%)

Depending on the available subsidies, San Francisco will issue H Bonds for its 150 MW Wind Power Facility for the period 2006-2008 (10% Admin)

2006 \$30 M
2007 \$120-50 Million H Bonds
2008 Option of More

4.0 Rights and Responsibilities

Rules and procedures previously developed for Direct Access and those currently in effect for municipal-owned utilities in California are directly applicable to San Francisco's CCA Program in many cases. Customer related rules and procedures need to address areas such as:

- consumer protection
- application for service
- notifications
- billing
- payment of bills
- establishment of credit
- maintenance of credit
- reestablishment of credit
- deposits
- billing adjustments
- billing disputes
- discontinuance of service
- shut-off
- relocation of service
- restoration of service
- return to IOU service

In D.04-12-046, the Commission decided to facilitate CCA implementation commencement immediately rather than waiting for the approval of permanent utility tariffs in Phase II of R.03-10-003:

“Delaying the implementation of CCA costs until after the resolution of Phase 2 of this proceeding could delay implementation of the CCA program until almost three years after passage of AB117” (Finding of Fact #31, p.62).

Accordingly, the Commission ordered PG&E and the other utilities to file provisional tariffs, outlining the rights and responsibilities of parties in a CCA:

“PG&E, SDG&E, and SCE shall, within 60 days of the effective date of this decision, file tariffs that are substantively identical to those in effect for direct access customers and which shall apply in the interim to Community Choice Aggregators (CCAs) prior to the Commission’s approval of final CCA tariffs” (Order #62, p.9).

Thus, the Commission determined that CCAs are authorized to proceed to implementation based on these interim tariffs:

“In all respects, utility tariffs and practices shall permit CCAs to initiate service immediately following the filing of tariffs described in Ordering Paragraph 2 (Order #9, p.72).

By way of compliance with these orders of the Commission, PG&E filed with San Diego Gas & Electric (SDG&E) and Southern California Edison (SCE) submitted Interim Tariffs to the Commission for approval on February 14, 2005.

As these tariffs are as yet unapproved by the Commission, the City and County protests the Commission’s abrogation of its fiduciary responsibility to its customers by transferring its authority over tariffs to the utilities it is required by the state constitution to regulate.

PG&E introduces its proposed tariffs, in effect, as regulation:

“Interim Rule 23 is effective on February 14, 2005 and shall immediately terminate on the effective date that the CPUC approves final rules in Rulemaking 03-10-003. On the specified effective date, the final version of Rule 23 shall immediately supersede interim rules in their entirety” (Filed February 22, 2005, Introduction).

Moreover, PG&E indicates that CCAs that execute the interim Service Agreement under the interim tariffs will still have to execute a new Service Agreement when the Commission approves tariffs in Phase II of R.03-10-003:

“Because the final tariff is to be incorporated by reference into an associated final Service Agreement, a CCAP that has executed the interim Service Agreement will be required to execute the final Service Agreement upon the Commission’s approval of the final CCA tariff” (*Ibid.*)

This assertion builds on the Commission’s unlawful delegation of regulatory authority to PG&E, by violating Order #9 in D.04-12-046 that utilities allow CCAs to commence service immediately, and places any CCA that responds to the Commission’s invitation to commence implementation in jeopardy.

Therefore, the City and County refuses to proceed with an outline of rights and responsibilities within the unapproved interim CCA tariff proposed by PG&E, and invites the Commission to request such information during the 90 day certification period.

V. PROGRAM IMPLEMENTATION

This section describes how the City and County’s CCA program is organized, its operations and funding. It includes clarification of the roles of the CCA’s governing board, CCA’s staff, and any outside vendors hired to assist in program development, implementation, and delivery. This section also explains the interaction between the CCA and PG&E, which will continue to provide metering, billing, and distribution service to the CCA’s customers, if this interaction varies from tariffed service.

San Francisco’s CCA program shall consist of the Board of Supervisors and Mayor authorizing, by a single ordinance, a retail electricity service provided by a single Electric Service Provider (ESP) for nine or more years, to all electricity ratepayers in San Francisco who are not now served by the San Francisco Public Utilities Commission.

The City Attorney shall be charged with enforcing contract compliance.

The City and County of San Francisco shall extend revenue bond financing for components of the 360 Megawatt service resource portfolio requirement that are designed, built, operated, and maintained by the City’s chosen Electric Service Provider for the duration of its agreement with the City as contained in its ultimate CCA Contract Award ordinance, the duration of which agreement shall be at least seven years, but may be longer, as determined by the Board of Supervisors in its RFP process and award of contract, pursuant to Public Utilities Code Section 366.2(c)(14).

During the period of the contract between the City and County and its chosen ESP, the ESP shall hold title to all facilities and contracts, and shall assume all risks associated with its service and competitively bid rates, as well as risks associated with termination from nonperformance. At the termination of the agreement, the ESP shall transfer the entire product of the renewable resource asset to the City and County of San Francisco, whereupon the City and County shall determine whether to transfer operations of said facilities to a subsequent Electric Service Provider, or to take them under management of the SFPUC or other agency.

The City and County, an agency, commission or task force, or its chosen contractor who is not a supplier or in any fiduciary relationship with the City's chosen Electric Service Provider of PG&E, shall provide supplemental services to facilitate the successful implementation of this Implementation Plan, including but not limited to data services and representation of the SF CCA, within the terms of nondisclosure agreement requirement set by the Commission on December 16, 2004 for any confidential information about any ratepayer participating in the CCA program, San Francisco shall never use the utility's information for any purpose other than to facilitate provision of energy services, pursuant to D.04-12-046 in R.03-10-003 on December 16, 2004 (p.52).

The San Francisco Public Utilities Commission may act as a merchant wholesaler of renewable capacity and or energy, including its Hetch Hetchy assets and potential new RPS compliant assets, in relation to the City's Chosen Electric Service Provider, as determined by the Board, Mayor and SFPUC Commissioners, but this potential shall depend upon the ultimate outcome of the City and County's chosen competitive bidding process, and cannot be determined by the City and County as of the date of this Implementation Plan. The City and County invites the Commissioners to request any such information, including any additional information necessary to determine a cost-recovery mechanism, over the next ninety days, in accordance with the state-local process provided by Public Utilities Code 366.2(c)(7), prior to certifying receipt of the plan.

1.0 Start-Up

As discussed in this Implementation Plan, there are a number of critical elements that must be advanced in parallel for the CCA Program to be successful. Accordingly, there must be an entity with full responsibility for its implementation. This entity needs to be committed to the success of the CCA Program, must have staff with excellent credentials and capabilities, and must have the required resources to advance the Program.

Beyond its functional responsibilities, the CCA Program will also have the duty to safeguard confidential data pertaining to current electric utility corporation customers, which PG&E is required to provide under Public Utilities Code Section 366.2 (c)(9). Throughout the course of the CCA Program, appropriate measures will be needed to ensure that confidentiality is maintained. The entity charged with implementing the CCA Program will need formal authorization from the City to request the data from the electrical utility corporation, and will need to be provided with the means and resources to manage the information such that confidentiality is preserved.

Through Resolution 757-04 of December 8, 2004, the SF Board of Supervisors authorized the formation of a seven member Community Choice Aggregation Citizen's Advisory Task Force ("Task Force") to advise the City on (1) the goals and preparation of a CCA Implementation Plan, (2) the use of Proposition H Bonds to accelerate the use of renewable energy, conservation and energy efficiency in the CCA program, (3) the requirements of the CCA bid solicitation process, and (4) the evaluation of bids.

The Task Force is currently operating on a voluntary basis. As the CCA Program advances, the level of effort required to manage it will increase. There are two alternative approaches available to address the need for increased levels of effort: The Task Force could evolve into a full time implementing entity with paid staff positions, or the Task Force could present a proposed process for the creation and staffing of an implementing entity with full time staff. The reporting requirements of the implementing entity to the Board of Supervisors would be addressed as a part of its formation process.

Regardless of which approach is used, a number of critical elements must be addressed.

1.1 Mission

A succinct description of the Mission of the CCA Implementation Program will need to be developed to be consistent with the provisions of this Implementation Plan, San Francisco Ordinance 86-04, and all applicable legislation and regulations. The Mission will include the list of objectives relating to the execution of all required CCA Program elements, and the expected schedule for the completion of each such objective.

1.2 Responsibilities

The implementing entity will be responsible for achieving the CCA Program objectives as set forth in the Mission Description. The implementing entity will report to the SF Board of Supervisors, and will be responsible for providing regularly scheduled progress reports to the Board of Supervisors over the course of the implementation phase.

The major responsibilities of the implementing entity include ensuring that:

- a. The implementation effort is conducted in full compliance with the San Francisco Ordinance 86-04, and all applicable statutory and regulatory provisions, including all elements of disclosure and due process in ratesetting, and provisions allowing customers to opt out
- b. The implementation effort results in the design and construction of the renewable power generation facilities specified in San Francisco Ordinance 86-04
- c. The implementation effort results in the load reductions through conservation and energy efficiency improvements specified in San Francisco Ordinance 86-04
- d. All required intergovernmental activities, stakeholder coordination and communications necessary to advance the implementation of the CCA Program are conducted
- e. The resulting CCA Program meets all requirements imposed by AB 117 and San Francisco Ordinance 86-04, and all applicable statutory and regulatory provisions, including all consumer protection procedures, credit issues and shutoff procedures

- f. The resulting CCA Program meets or exceeds the City's RPS goals, verified in compliance with RPS compliance reporting requirements, which are currently under consideration as a part of CPUC Rulemaking 04-04-026.

The implementing entity will be authorized to secure consulting and legal services as necessary to support the implementation of the SF CCA Program, using appropriate City of San Francisco services procurement processes and guidelines.

1.3 San Francisco Public Utilities Commission (SFPUC) Role

The SFPUC has been a contributing participant in the development of the CCA Program and will continue to play a number of important roles. The SFPUC General Manager will appoint a member of the Task Force with expertise in energy resources planning at the SFPUC.

The CCA Program will implement a set of renewable power infrastructure programs as provided for under Ordinance 86-04, funded by Proposition H revenue bonds. When the bonds have been repaid, the ownership of the infrastructure will revert to the City. At this point the City may elect to transfer the infrastructure assets to the SFPUC.

It is also likely that some or all of the wind power capacity requirements provided for under Ordinance 86-04 could be built on Hetch Hetchy property, and that the wind power generated would be integrated into the Hetch Hetchy transmission system. With regard to the Hetch Hetchy wind power infrastructure, the SFPUC would be involved in all phases of the implementation, in integrating the power transmission, and as the ultimate manager of the assets. As with the other Proposition H funded renewable infrastructure components, the ownership of the wind power assets would revert to the City once the bonds have been repaid, At this point the City may elect to transfer the infrastructure assets to the SFPUC.

1.4 Implementing Entity Organizational Structure

The implementing entity will be staffed with highly qualified individuals, and have the responsibility for executing the CCA Program. The implementing entity will be a single purpose entity. Its overall mission will be to establish the CCA and to implement all of the renewable power generation infrastructure, and conservation and efficiency

measures required by Ordinance 86-04. As a single purpose entity, it will disband when the implementation phase is completed. It would consist of a core team of executive staff, working with a support staff and consultant team in a dedicated CCA Program office.

The establishment of a special purpose CCA Program implementation entity will provide the following benefits:

1.3.1 Single Mission Staff

The implementing entity executive staff will be selected from a range of candidates that have demonstrated a substantial level of relevant and successful experience in the implementation of complex programs. The individuals chosen to lead and work on this effort as employees of the implementing entity would be assigned full time to their specific CCA Program roles and would have no other work responsibilities. Specific skill areas are discussed further in Section 1.3.4 “Efficient Staff Structure.”

The goal of structuring the implementing entity staff roles and the management organization will be to create an organization with the greatest potential for success in implementing the CCA Program. Assembling a team of well qualified individuals, with a given single mission, will create levels of capability and focus appropriate to address the challenges inherent in CCA Program.

1.3.2 Dedicated Location

The establishment of the implementing entity in a dedicated office space will greatly enhance its efficiency and its capability to successfully implement the CCA Program. Compared to the expected physical distribution of staff if the CCA was implemented by an existing agency, co-location ‘centers’ the effort, and improves the efficiency of the implementation process in a number of ways.

Having the staff located in the same working space will eliminate much of the communication lag that can occur when a project team is spread across different locations and different organizations. Instead of waiting hours or days for people to return messages, or to be available for meetings, tasks can be often be progressed very quickly in a co-located setting. Co-location can also result in better information distribution. Team members tend get more ‘word of mouth’ information in a co-located

setting, and they get it faster. Formal information management is also more efficient in a co-located setting, as the program specific records center would be easily accessible to staff.

1.3.3 Financial Management

The implementing entity will need to manage a range of financial transactions and information, including confidential information. This includes all phases of structuring the Proposition H bond issuance and managing the resultant funds, all funds related to any required property acquisitions, the management of all contract accounts and invoices, from the ESP and other vendors involved in advancing the program, the management of the ESP and consultant contracts, and may also include a range of ratepayer cost and/or payment tracking.

Having these functions consolidated in a financial management office specific to the CCA will bring a number of benefits. It will allow for the senior management team and thus the Board of Supervisors to have a single point of contact for all financial matters. All of the financial functions would be conducted by one set of staff, and the CCA financial records would be in one consolidated location.

1.3.4 Efficient Staff Structure

As discussed above, it is expected that the core senior staff of the implementing entity would have been selected from a range of well qualified candidates, and their skills would be well suited to their roles. At a more junior level, the implementing entity would also employ a small core support staff, whose roles were broader, designed to suit the ongoing needs of the CCA Program.

Possible Executive Level positions for the implementing entity include:

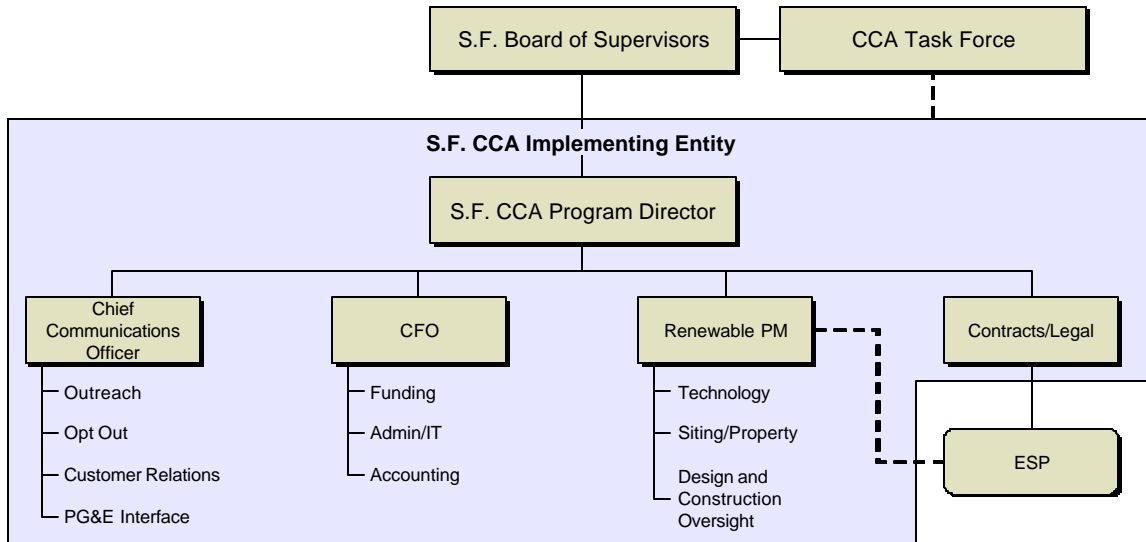
- Program Director
- Financial Officer
- Contracts Officer
- Technical Officer and Project Manager
- Communications/Outreach Officer
- Property Rights Acquisition Officer
- Construction Management Officer

Instead of building a larger full time team to provide all of the skills required to implement the CCA Program, the implementing entity will be able to structure consultant services contracts to provide skills needed for particular phases of the program on a task basis. This structure allows the right skills to be available when needed. It also allow the Program to be more cost effective, carrying a smaller core staff, and applying skills only when needed. The SFPUC, in its March 11, 2005 LAFCO presentation on its progress with the draft CCA Implementation Plan indicated that it would need a team of 77 people, at an annual cost of \$9 million to implement the CCA Program. In contrast, it is expected that the establishment of a single purpose implementing entity could implement at a substantially lower annual cost, on the order of \$5 to \$6 million.

A sample organizational chart showing the roles proposed above is provided as Exhibit V-1:

Exhibit V-1

**S.F. CCA
Program Implementation Entity Organization**



1.4 Implementing Entity Budget and Funding

The implementing entity may initially be funded through general funds. Proposition H bond funds are available for financing or refinancing the acquisition, construction, installation, equipping, improvement or rehabilitation of equipment or facilities for renewable energy and energy conservation. The CCA Program will incur costs related to the Proposition H bond purposes and for other CCA program purposes. The general funds initially expended for Proposition H bond purposes would be refunded once the Proposition H bond is issued. The Task Force will develop the mechanisms for tracking and segregating the expenditure of general funds and Proposition H bond funds.

The implementing entity will be expected to manage the budgets necessary for the implementation of the CCA Program, at a strict level of financial diligence, in order to ensure that the program does not exceed its authorized funding levels. Providing regular, detailed financial reports to the Board of Supervisors would be one of the responsibilities of the implementing entity.

2.0. Program Development

The Program Development phase will consist of the development and refinement at a detailed level of the processes necessary to successfully implement the ultimate goals of the CCA Program, including the renewable power generation infrastructure, efficiency and conservation required under Ordinance 86-04, and all other program elements.

This process will consist largely of the identification of open questions and issues that need to be addressed and closed prior to the issuance of the RFP for the ESP, but it will also cover any open non-ESP issues that need to be addressed to advance the CCA Program. These subjects arise across a disparate range of subjects, some of which are addressed in this document. Some representative examples of open issues are:

- How will rate payer confidential data be managed?
- What roles will the CCA Program and the ESP respectively play as to site acquisition and attendant agreements for the installation of the renewable power generation infrastructure elements?
- What performance and durability requirements will apply to the renewable power generation infrastructure components to be provided by the ESP?

As a part of the Program Development Phase, there will be an effort to gain insight and knowledge from other Community Choice Aggregation Programs. This may include review of their program documentation, and may also include meetings with key staff to discuss the approaches they used for their Community Choice Aggregation Programs.

The program development phase conclusions will be compiled in a 'Program Basis Report' which, category by category, will describe how each element of the CCA Program will be addressed.

2.1 Rate Design, Rate Setting and Other Costs

This section explains the process by which rates and other costs will be established, including public participation in that process.

Public Utilities Code Section 366.2(c) 3 (B) and (C) require San Francisco's Implementation Plan to contain rate-setting and other costs to participants. The City and County interprets this requirement to mean a presentation of the basic principles and structure of its rate-setting mechanism, not a submission of rates to the Commission for approval. Public Utilities Code Section 394 (f) provides that registration with the Commission is an exercise of the licensing function of the commission, and does not constitute regulation of the rates or terms and conditions of service offered by any prospective ESP. Indeed, the statute provides expressly that nothing in the registration requirement authorizes the Commission to regulate the rates or terms and conditions of service offered by the City and County's chosen ESP. Furthermore, Public Utilities Code Section 366.2(c)(7) requires the Commission to certify receipt of the Implementation Plan, not to approve or reject it. Therefore, the City and County's ratesetting mechanism is not required to conform to the "utility approach" to setting rates, involving the calculation of a rate of return on the utilities rate base including depreciation.

Nor is the City and County setting rates as a municipally-owned electric utility, Municipal Utility District or other wholesale power entity subject to federal regulation. Ordinance 86-04 requires that this Implementation Plan require that the ESP bids and any contract with an ESP include proposals for rate design, with all costs associated with providing all the costs associated with providing all the various components of the City and County's proposed service package, including the costs of designing, building, operating and maintaining all renewable energy, conservation and energy efficiency installations, as well as any capital, insurance and other costs associated with fulfilling the commitments made in its bid to the City and County (Ordinance 86-04, Section 3 (1)(III), p.5). Accordingly, Ordinance 86-04 also establishes an RFP ESP bidding requirement that

"bids by prospective Electric Service Providers shall include a proposed rate design, with all costs and profits associated with providing the various components of its proposed service package, including the costs of designing, building, operating and maintain all renewable energy, conservation and energy efficiency installations, as well as any capital, insurance and other costs associated with fulfilling the commitments made in its bid to be reflected in a per kilowatt hour rate schedule that is comparable to PG&E's rate schedule and consistent with the resource portfolio requirements and rate-setting mechanisms

adopted in the City's adopted Implementation Plan." (Ordinance 86-04, Section 4 (D), pp.8-9).

Furthermore, Ordinance 86-04 establishes a second RFP bidding requirement that

"the RFP shall require that qualifying Electric Service Providers post a bond or demonstrate insurance sufficient to cover the cost of reentry fees in the event that customers are involuntarily returned to service provided to PG&E, pursuant to Section 394.25(e) of the Public Utilities Code, and shall bid an insured electricity rate schedule, similar in structure to that appearing on monthly utility bills, which conforms to the City's ratesetting mechanism contained in the City's adopted Implementation Plan" (Ordinance 86-04, Section 4(E), p. 9).

The first new element of the City and County's rate-setting mechanism established by this Implementation Plan is a requirement that the ESP's required rate schedule include, in addition to costs associated with the renewable resource, conservation and efficiency portfolio element and the risk of contract failure, that it shall also include all costs associated with any and all liabilities of meeting the resource adequacy requirement for all LSEs contained in its January 22, 2004 decision in R.01-10-024. Thus, the City and County's rate-setting mechanism relative to resource adequacy consistent with Ordinance 86-04, namely that qualifying bids shall incorporate this energy and risk within its competitively bid rate schedule.

Thus, the City and County is not forming a municipal utility or Municipal Utility District, and remains subject to the jurisdiction of the Commission, not the federal government. Rather, the City's RFP shall require qualifying ESPs to assume the full risk of the rates they bid, including resource adequacy requirements and the three (3) year 360 MW rollout, and also requires the ESP to cover risk associated with a worst case scenario of contract failure.

Thus, the City and County is not limited to the "cash needs approach" based on the projected cash needs of the entity, under which the allocation of shared costs and overheads are recovered through rates, and thus potentially rate increase. Rather, under the City and County's rate-setting mechanism, the ESP shall be required to manage the risks associated with its competitively bid rate schedule, such that a mis-projection of the cash needs of the ESP, under which a mis-allocation of unanticipated costs and overheads by the ESP shall not be recovered from participating San Francisco

ratepayers, but shall be born by the ESP's owners or another party that underwrites or enhances the credit of the ESP. In this manner, the City and County's award of contract to an ESP shall constitute its single and only action as a rate-setting authority within the scope of this Implementation Plan, except for any decision to increase development of renewable resources, conservation or energy efficiency technologies through a contract extension and subsequent bond issuances by the Board of Supervisors, as the Board determines, with a goal of achieving an RPS consisting of all new facilities of 51% by 2017.

While the rate-setting function of San Francisco's CCA program is neither regulated by the Commission nor limited to cash needs approach of municipal utilities, the City's rate-setting function must be reasonable, and may also be subject to charter and/or municipal code restrictions, including bond covenants (The California Municipal Law Handbook, p.IV-78 (2002 ed). Specifically, San Francisco's Charter authorizes the Board of Supervisors to provide for the issuance of revenue bonds "to finance or refinance the acquisition, construction, installation, equipping, improvement or rehabilitation of equipment or facilities for renewable energy and energy conservation, in accordance with state law or any procedure provided for by ordinance (San Francisco Charter Section 9.107.8).

Predicting PG&E's generation rates, the major competitor to CCA, is a complex forecasting exercise. PG&E no longer provides an open-book review of their resource mix and power contract terms – indeed due to concerns about use of market power and negative impacts on PG&E ratepayers a substantial amount of information regarding PG&E's contracts is now held confidential by the CPUC. This makes the forecasting of PG&E's average generation rates a complex process. Of course allocation of PG&E's generation costs among customer groups is also a dynamic process subject to CPUC regulation. PG&E's current rate allocation proposal in its General Rate Case (GRC) would, if approved by the CPUC, significantly lower generation rates for large and medium customers in CCSF while increasing generation rates for higher consumption residential customers. The net effect of PG&E's proposal would be to decrease the average PG&E generation cost for CCSF customers thereby increasing the competitive pressure on CCA generation rates.

Ultimately, the ratesetting goals established by the Board of Supervisors will determine what model is used for the supplier RFP. For example at one end of the spectrum, some large energy buyers provide their energy usage history by customer category in an

electric supply RFP and ask for the best price for each category. The winning bid sets the rate for that category. On the other end of the spectrum, customers can identify an index on which to peg rates as well as the rate structure desired – for example a percentage discount off of each customer’s PG&E rate schedule. To the extent that the constraints established by such an RFP approach create risk, the price of risk mitigation to meet proposed contract terms will be factored into RFP bid responses

D. 04-12-046 imposed a 2.0 cents/kWh CRS for all CCA customers for an 18 month period. This will effectively be reduced to a new 1.8 cents/kWh charge for PG&E customers who are served by a CCA since PG&E already charges approximately 0.2 cents/kWh for CTC that will be eliminated for CCA customers.

Treatment of Low-Income Customers Requires Special Consideration

A key aspect of residential rates regulated by the CPUC is the California Alternative Rates for Energy program (CARE). As discussed briefly in Chapter 2, this program applies to residential customers of PG&E and other investor-owned utilities and provides about a 40% discount from average total residential bills for customers with incomes up to 175% of the Federal poverty line. In CCSF about 17% of residential customers are currently *participating* in CARE.⁸ This is slightly lower than the 21% of PG&E’s residential customers that are participating in CARE system-wide. Moreover, according to PG&E the CARE program has a higher penetration rate in San Francisco (82%) than it does on average throughout PG&E’s system (70%). This means that there are fewer customers eligible for CARE and not participating in the program in San Francisco than in the rest of PG&E’s service territory. Within CCSF these customers currently have average monthly bills of \$26.27 of which \$8.79, or 33% is constituted by the generation portion. Assuming the CCA would offer CARE rates identical to those offered by PG&E this might require, at least in the early years, a discount higher than the 40% currently offered by PG&E.⁹ It is currently unclear from CPUC proceedings whether the subsidy for the CARE discount will be the responsibility of all of PG&E customers regardless of the generation supplier – this would make the CARE program CCA revenue neutral and will be addressed in Phase 2 of the CCA proceeding. However, the impact on CCA revenue of the CCA offering both the CARE discount, and the source of recovery of any revenue shortfall associated with CARE may have an impact on CCA rates.

By law, CCAs will use existing utility billing systems. Thus, PG&E will be billing CCA customers on a monthly basis probably using PG&E’s rate-ready billing option already

used by some ESPs for direct access. CCSF will provide PG&E electric generation rates (and where appropriate electric demand charges) for each rate schedule the CCA serves. This rate ready billing option currently costs 70 cents/bill/month. For CCSF as a CCA the yearly cost of using this approach is about \$2.6 million (assuming zero opt-out of CCA). This approach is simple and means that a customer will not receive a new bill due to CCA. However, the rate-ready billing method limits the options for CCA ratesetting to rates designs which can be implemented within the current PG&E billing system.

PG&E's Phase 2 proceeding is underway at the CPUC and expected to be decided by the Commission by the end of 2005. PG&E has indicated that it would like to settle this proceeding. There will be active participation from residential, commercial, industrial, agricultural, and street-lighting customers, the latter of which are cities and counties. PG&E's revenue allocation proposal is to increase residential revenue allocation, maintain small business customers close to current revenue allocation, and provide a sizable decrease for the majority of medium and large customers (with the exception of standby customers who would see a revenue allocation increase).

Compared to 2004 energy generation charges this overall revenue allocation proposal translates into energy generation charges which are: increased across the board for residential customers including CARE customers, slightly decreased for small commercial customers; and significantly decreased for medium commercial, large commercial, and the largest commercial/industrial customers. The overall impact of the proposed revenue allocation and rate design change is to decrease the overall generation cost to serve CCSF by half-cent/kWh or about 6%. Based on 2003 loads and early 2005 PG&E generation rates, the average generation cost to serve CCSF customers was 6.3cents/kWh. Should this PG&E GRC Phase 2 proposal be approved as filed by the CPUC this average PG&E generation cost to serve will drop to about 5.9 cents/kWh.

This average generation rate would provide a formidable challenge to making CCA economic. For example, assuming an average 1.8-cents/kWh CRS energy charge then the all-in cost to serve CCSF customers could not competitively exceed 4.1cents/kWh in 2006. [last sentence deleted]

One of the more complex issues for PG&E's proposed rate design is how to set residential rates. This is because there are many constraints on residential rates that have been imposed by legislation and prior CPUC decisions.

The first constraint was imposed by the passage of AB 1X in January 2001. As discussed in Chapter 2, this legislation permitted *no* increase in residential rates for customer usage up to 130% of the customer's baseline amount. The baseline amount has been set in CPUC proceedings and varies by climate zone and type of energy usage in a dwelling (e.g. mix of gas and electric usage). This prohibition of any rate increase has meant that any residential rate increases must be applied to usage in excess of 130% of baseline. About 73% of PG&E's residential consumption is protected from rate increases because of this legislation and other CPUC-imposed restrictions on increases for customers receiving CARE rate (for low income customers) or on medical baseline allowances. Thus any rate increases must be imposed on only 27% of residential usage, or be shifted to other customer classes.

In Phase 2 of its current GRC, PG&E proposes to try to allocate the shortfall from the 130% of baseline rate-cap within the residential class. However, PG&E also proposes to cap the overall residential increase, which means some of the costs will spill over to other classes. The other classes will oppose this shift of costs in their direction. This debate in the PG&E rate proceeding illuminates how similar ratesetting issues may affect the CCA product design.

Related to the baseline rate issue, PG&E's residential customers have increasing block rates. Baseline usage sets the amount of energy in the first residential tier, while the second tier includes usage from 101% to 130% of baseline usage. There follow three tiers with increasing rates for increasing usage, with the blocks sized on the basis of the baseline quantity for the customer in its climate zone.

In the GRC Phase 2 proceeding, PG&E proposes to retain five residential tiers but establish the same rates for Tiers 4 and 5. CCSF will need to consider whether it also wants to establish a comparable tiered residential rate structure. If so, it should consider whether it wants its rate tiers to increase such that it maintains the same price differential among the residential rate tiers as does PG&E. But the rate-ready billing requirement will require that the overall structure of CCA rates fit within PG&E's billing constraints. PG&E also makes proposals for larger customers in its Phase 2 proceeding.

- Mandatory TOU (Time of Use) rates for all customers over 500 kW

- Voluntary TOU for all smaller customers
- Choice of rate options for smaller customers, e.g. optional demand charges and/or TOU energy charge options
- Revenue neutral TOU and non-TOU rates for customers less than 500 kW
- Switch all customers above 500 kW to recording usage at 15 minute demand intervals for meters with this capability
- Increase in customer charges, with greater increases for higher voltages
- Seasonal differential in distribution related charges at 1.5 (summer): 1.0 (winter)
- TOU Ratio of summer combined distribution demand and energy charges: 2.5:1.0:0.5
- TOU Ratio of winter combined distribution demand and energy charges: 1.5:1.0
- Collect 20% of allocated generation revenue as capacity (20% through demand charges for higher voltage customers and less for lower voltage customers) with rest in TOU energy charges
- Customer charges for standby customers (which would apply to backup service for self-generation or distributed generation customers) will be the same as for full requirements customers; standby customers will also pay peak demand-related distribution revenues on a TOU kWh basis, and will pay all other generation and distribution costs as reservation charges.

Some of PG&E's large customers take interruptible service. They receive lower rates in exchange for being available to shut down their usage in case of system supply or reliability emergencies. Given its load pocket characteristics CCSF may have to investigate whether to encourage such an option for its own customers. CCSF must consider whether it would like to pay incentives and have its own program for load reductions so that it can get credit for demand response for resource planning purposes.

If CCSF chooses to do so, it must decide whether or not to set its incentives at the same level as PG&E or greater. Additionally, CCSF would have to consider whether its

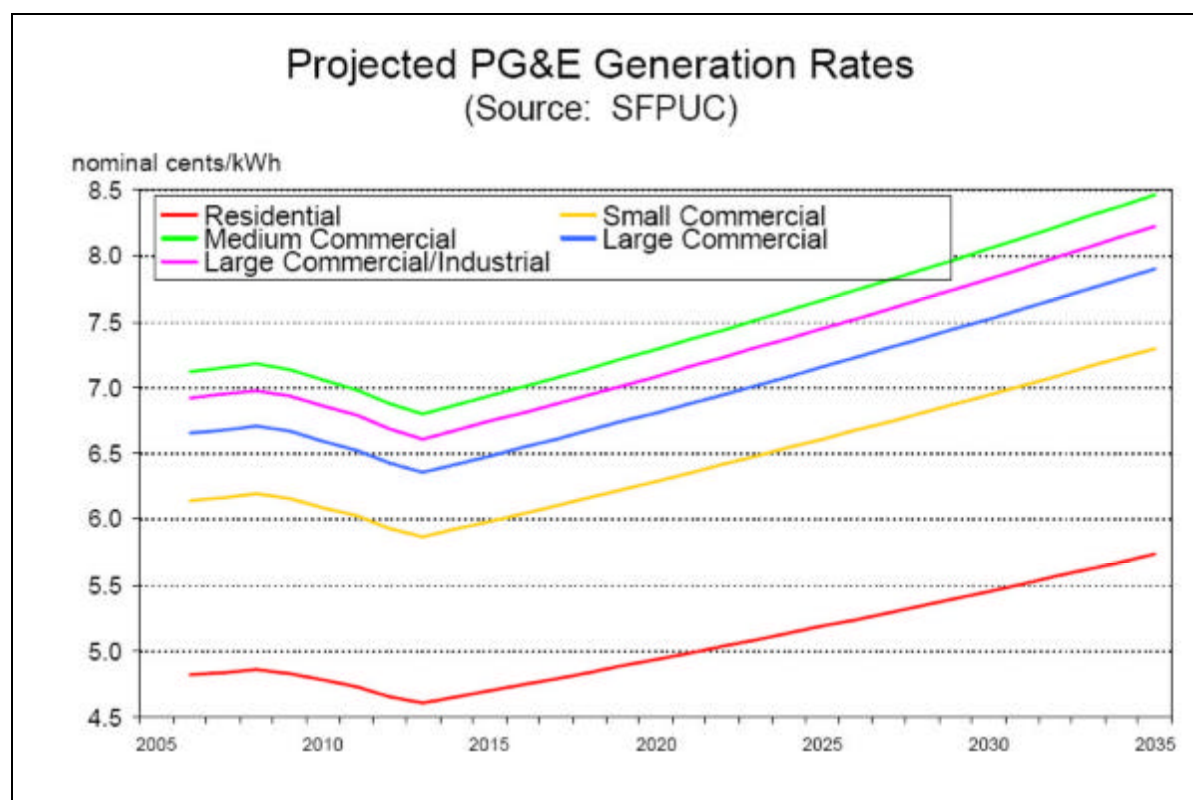
customers could participate in both load reduction programs, or if there could be double counting of demand reduction as a result. CCSF would also have to decide to coordinate its demand response program directly with CAISO, through its supplier, or through PG&E.

CCSF may decide to pursue “demand response” rates, such as Critical Peak Pricing (CPP) and Real-Time Pricing (RTP). These rate options are designed to charge high rates when supplies are tight or reliability is threatened, in the expectation that customers on these rates will reduce their usage. All of these rate options require advanced metering. Currently these meters and rates are only available to PG&E’s larger customers.

The competitive landscape for demand response rates is in flux. The CPUC has ordered PG&E and other utilities to provide plans by March 15, 2005 for expanding advanced metering. In addition, the CPUC has ordered PG&E to file critical peak pricing default rates for implementation in summer 2005 for all customers over 200 kW.

Such rate options (e.g. interruptible, CPP, RTP) could be part of CCSF’s demand response component of its resource plan, to help meet resource adequacy goals.

Besides power procurement and the CRS, a CCA will have also incur other costs that it must recover from its customers. The most significant of these are: billing charges from PG&E; its own administrative and operational costs (most notably a call center); and charges assessed by the CA-ISO. As seen in Figure 6, for example, these other CCA charges are a minuscule portion of the CCA’s total costs each year. As such, the other factors discussed above will have a much greater impact on the CCA v. PG&E cost comparison over the long term. Nonetheless, the Contract Mix Model has been designed to accept alternative assumptions on all of these other CCA costs, to evaluate the potential impacts on the cost comparison.

Add following figure to discussion of projected rates:

If there are to be Supplemental Energy Payments (as defined by the CEC), these payments would be made outside the price system for electricity generation (however they may be incorporated as higher electricity distribution rates). ... In the CCA v. PG&E cost comparison, we identified favorable cases for the CCA option that assumed the CCSF CCA built its own renewable energy for its peaking (6x16) needs only. The Contract Mix Model calculates the share of this renewable energy in the CCA's overall portfolio. The cases we investigated showed that the share of this 6x16 renewable energy was only about 13 percent of total energy supplies in any given year. This result leads us to believe that LSEs cannot expect to meet the RPS on a percentage-of-consumption basis with peaking supplies only, and that they will likely have to include renewable resources in their baseload supplies. Alternatively, LSEs generating and selling renewable power could keep any RECs for themselves as an approach to meeting the RPS standard.

The Contract Mix model allows for the overlay of the presumed regulatory requirements for CCA contracting. According to Altos' and the SFPUC staff's understanding, CCAs will, by CPUC regulation, have to meet certain requirements both

forward contracting and reserve margin to ensure resource adequacy. The Contract Mix model accounts for both of these regulations.

The current understanding of the forward contracting requirement is that:

1. By September 30 of every year, every LSE must contract for capacity for at least 90% of its projected load for each month in the following peak summer season (i.e., the following May through September); and
2. all LSEs will have to be fully contracted for capacity and energy at least one month ahead of time to meet expected loads.”

These regulatory scenarios leads naturally to questions about the development of separate markets for generation capacity and electric energy in California, and the potential linkages between these two markets. While some might suggest that the capacity market and the energy market will be entirely separate, distinct, and independent, Altos believes, to the contrary, that the markets for energy and capacity, as expressed in their prices, will be absolutely linked, and that they cannot be un-linked.

To understand this point, let us understand that an LSE would make capacity payments to a generator in, say, September 2006 to “lock in” generation if the LSE needed to call on it during May – September 2007. Then, if the LSE needs the power from that generator, the LSE would make an energy payment to the generator and the power would be generated and consumed. In this construction, the capacity payments would generally cover the generator’s fixed costs, while the energy payments would typically cover fuel and other non-fuel operating costs (if any). The question arises, then, what will be the relationship among the capacity payment (made in September 2006), the energy payment (made in Summer 2007), and the prevailing price for spot energy (the “all in” price during Summer 2007)?

Altos believes that the sum of the capacity payment and the energy payment must equal the spot price (at any hour that the LSE calls for power from the generator):
Capacity + Energy = Spot ($C + E = S$). No other solution is economically rational. Consider the LSE. Hour-by-hour, his supply alternatives are: purchase power from the generator he has under capacity contract or purchase from the spot market. The rational LSE will not, consistently and over the long-run, pay more to the contracted generator, in total (i.e., for capacity plus energy), than the power is worth in the spot market at any given hour. On the other hand, the rational generator cannot expect to receive, consistently and over the long-run, capacity and energy payments whose sum exceeds the market-determined value of power on an hourly basis. Both sides will expect to be

“price takers” in the very large WECC market of generators and purchasers, and the price that both sides will calibrate to is the hourly “all in” or spot price.

This calibration to the spot price means that capacity payments and energy payments will have an inverse relationship. If capacity payments are high, the subsequent energy payments (made when the electricity is actually needed) will be low. If the capacity payments are low, the energy payment will be high. In every case, the energy payment will make up the difference between the capacity payment and the spot price at the time the energy is delivered.

This inter-relationship among capacity, energy, and spot prices is captured in the NARE Model and the Contract Mix Model. We represent the CCA purchasing power contracts at an “all in” price (i.e., the sum of capacity and energy). This “all in” price reflects the total cost to the CCA for this power. While in the “real world” these payments would be made at two different times (capacity in September and energy in the following summer), the total cost to the CCA is the important value, and that value is reflected in the “all in” price that we use.

The Contract Mix Model represents the reserve margin requirements by increasing the amount of power the CCA must have contracted for the peak demand periods, using the following input factors (found under Miscellaneous Inputs):

Resource Adequacy Reserve Cutoff: This factor indicates the hours for which the reserve adequacy requirements are in effect. The current understanding of prospective CPUC regulations on this issue is that the reserve adequacy requirements will be in effect during all hours when the projected load is expected to be at least 90 percent of maximum load (i.e., the 10 percent of hours with the highest load).

Resource Adequacy Reserve Margin: This factor determines how much extra power needs to be contracted for during these hours. The current understanding of prospective CPUC regulations on this issue is a 17 percent reserve margin.

Coincidence Factor: This factor reduces the necessary reserve margin, to account for non-coincident peak loads. The current simplifying assumption regarding prospective CPUC regulations on this issue is for a 2.5 percent factor.”

Using the currently proposed values, for each of the top 90 percent of hours, the CCA would have contracted an amount of power equal to: Base Load x 1.17 x (1-0.025) or about 114.1 percent of the projected load.

These resource adequacy requirements, if enacted by the CPUC, would constrain a CCA's contracting program to a "net long" position in every month (see Figure 25 above) if purchasing standard 7x24 or 6x16 wholesale market products. Thus, unless the CCA customers' power demand unexpectedly exceed the forecasted demand (e.g., due to hotter-than-average summer weather), the CCA would be selling excess contracted power every month into the spot market, presumably at spot prices.

2.2 Disclosure And Due Process In Setting Rates And Allocating Costs Among Participants

Consistent with Section 2.2.3 "Rate Design, Rate Setting and Other Costs " above, this section describes how the CCA will disclose to its customers and governing board information about rates and costs, and the public participation process for rate setting and cost allocation proceedings.

The City and County will ensure that adequate notice is provided to electricity customers during the rate-setting process, which consists of the RFP process, the award of contract by ordinance and opt-out notifications. Towards this purpose, and consistent with the Sunshine Ordinance and open meeting laws, the City and County will continue to conduct public hearings at every juncture of the CCA decision-making process, and shall provide notifications to customers as required by 366.2(c)((13)(A), (B) and (C), using a single page insert with a detachable postage-paid opt-out card, in which the City and County shall fully inform participating customers at least twice within two calendar months, or 60 days, in advance of the date of commencing automatic enrollment. Notifications may occur concurrently with billing cycles.

Following enrollment, the City and County shall fully inform participating customers for not less than two consecutive billing cycles. Notification in San Francisco's utility bill inserts may be supplemented by direct mailings to customers, or inserts in water, sewer, or other utility bills. Any notification shall inform customers of both of the following:

- (i) That they are to be automatically enrolled and that the customer has the right to opt out of the community choice aggregator without penalty.
- (ii) The terms and conditions of the services offered.

Toward this purpose, the Board of Supervisors has requested the Commission to order PG&E to fully cooperate with the City and County in determining the feasibility and costs associated with using the electrical corporation's normally scheduled monthly billing process to provide all four (4) of the notifications required pursuant to

subparagraph (A) by inserting the City and County's notification in the electrical corporation's normally scheduled monthly billing process. Consistent with AB117, the City and County will pay the reasonable cost the electrical corporation shall be entitled to recover from it all reasonable incremental costs it incurs related to the notification or notifications, as determined by the Commission.

Furthermore, Ordinance 86-04 establishes that this Implementation include a requirement that qualifying ESP bids shall offer a rate schedule comparable to PG&E's so that ratepayers may competently judge whether to opt-out of the City and County's chosen new energy service:

"The RFP shall require that bids by prospective Electric Service Provider shall include a proposed rate design, with all costs and profits associated with providing the various components of its proposed service package, including the costs of designing, building, operating and maintaining all renewable energy, conservation and energy efficiency installations, as well as any capital, insurance and other costs associated with fulfilling the commitments made in its bid, to be reflected in a per kilowatt hour rate schedule that is comparable to PG&E's rate schedule and consistent with the resource portfolio requirements and rate-setting mechanisms contained in the City's adopted Implementation Plan" (Ordinance 86-04, Section 4(D), pp.8-9).

Furthermore, Ordinance 86-04 requires that the Implementation shall include a similar provision that ESP rates shall include all costs, inclusively, of the bundled product:

"Appropriate contract and bid requirements, including...III. A requirement that bids include proposals for rate design, with all costs and profits associated with providing the various components of its proposed service package, including the costs of designing, building, operating and maintaining all renewable energy, conservation and energy efficiency installations, as well as any capital, insurance and other costs associated with fulfilling the commitments made in its bid" (ordinance 86-04, May 27, 2004, p. 6).

Pursuant to Public Utilities Code 366.2 (c)(13)(C), each notification shall also include a mechanism by which a ratepayer may opt out of community choice aggregated service. The opt out may take the form of a self-addressed return postcard indicating the customer's election to remain with, or return to, electrical energy service provided by PG&E, or another straightforward means by which the customer may elect to derive electrical energy service through the electrical corporation providing service in the area.

Furthermore, Ordinance 86-04 requires that under the bidding requirements of its Implementation Plan and RFP, the ESP, not the City and County or its participating ratepayers, shall assume all liabilities associated with an involuntary return of San Francisco CCA customers to PG&E:

“The RFP shall require that qualifying Electric Service Provider post a bond or demonstrate insurance sufficient to cover the cost of reentry fees in the event that customers are involuntarily returned to service provided by PG&E, pursuant to section 394.25(e) of the Public Utilities Code, and shall bid an insured electricity rate schedule, similar in structure to that appearing on monthly PG&E bills, which conforms to the City’s rate-setting mechanism as adopted in its Implementation Plan, pursuant to 366.2(c)(3) of the public Utilities Code.” (Ordinance 86-04, p.9).

Thus, the City and County ensures that ratepayers are provided due process relative to not only rates, but also relative to the risks associated with nonperformance by the City and County’s chosen ESP and involuntary return to PG&E procurement.

Another risk reduction option would be for the CCA to also levy an exit-fee of some type on customers who leave the CCA for other electric service. [after the statute mandated free opt-out period]

Finally, the Board of Supervisors shall require that ESP rates shall include costs associated with managing the risks of an annual true up of the CRS pursuant to D.04-12-046.

If a customer declines to opt-out but later wishes to return to PG&E service, it will face CPUC-imposed switching rules to return to PG&E service. These rules might include a minimum time on rates tied to wholesale electric spot prices and/or a minimum commitment to remain a PG&E customer.

PG&E rates are set under the CPUC ratemaking process. First, PG&E’s revenue requirement for a future time period is set based on the forecasted cost to serve its forecasted demand for power over that period of time. The annual revenue requirement is the amount of money that PG&E must collect through billing its customers over a year, including capital costs, variable costs (including fuel and O&M), contract costs, taxes, and return on investment. The proceeding in which the revenue requirement is determined is called Phase 1 of a General Rate Case (GRC).

The revenue requirement is allocated over PG&E’s forecast sales in Phase 2 of the GRC to determine the average rate that must be paid by each class or rate schedule of

customers in order to produce that amount of revenue. Since it is spread over *forecast* sales, the amount of revenue actually collected will never exactly equal the revenue requirement. Excesses or shortfalls in revenue are tracked and applied to adjust the revenue requirement for the following year. PG&E is also authorized annual revenue requirement adjustments for inflation and capital additions, called attrition adjustments. Separately, PG&E has an annual review of its generation costs, with annual rate adjustments. More frequent adjustments are permitted if its costs and revenues diverge by more than five percent.

Once the revenue requirement is determined, it is allocated among customer classes and rate schedules within the customer classes. The basic framework for this allocation is set every three years in Phase 2 of GRC. The revenues to be collected are allocated among the various customer classes based on the marginal cost of serving the different classes. Next, revenues to be collected within a class are allocated to rate schedules within each class. Once the revenues have been allocated, rates are set such that the usage characteristics expected of the sales for that group of customers, when multiplied by the rates, will produce the desired amount of revenue.

Some classes, like residential, simply have charges per kWh of usage. Others also have demand charges, based on the maximum instantaneous demand of a given customer over a month, or the maximum demand during the peak period of system demand. Some have time-of-use rates, where the kWh charges vary by time of day. Lastly, some customer classes pay customer charges, which are fixed charges per month designed to capture the fixed costs of serving the customer, like metering and billing.

For the purpose of CCA service, the key factor for CCSF is allocation of revenues to recover supply costs, since PG&E's delivery, metering and billing costs are included in PG&E delivery charges. PG&E's generation costs include the utility's own generation costs from its power plants and purchased power contracts, as well as a share of DWR contract costs, as determined by the CPUC through its allocation methodology for DWR power contracts.

The utility must also recover other generation related costs like CTC and DWR Bond Charges from *all* customers, including CCA and non-exempt DA customers, as part of its delivery charges. In the case of a CCA, its generation costs will be those of the supplier contract plus the CRS charged to CCA customers by PG&E. This is why CCAs have to account for the CRS charge in their economic evaluation since this is a new rate component that CCA customers will be paying. A CCA may also include additional costs incurred for energy efficiency, demand response, or renewables acquisition undertaken by CCSF itself, as opposed to by its supplier, in its generation rates.

Generation-related costs for utilities are recovered using demand and energy charges for larger customers and energy charges for smaller customers. As noted above, CCSF will have to decide whether to model its generation rates after those of PG&E, i.e. with demand and energy charges, often varying by time of use, for appropriate customers, or whether to model its rates after the charges imposed by its supplier, which may only be energy-related (i.e. volumetric) charges.

CCSF will also have to decide how to adjust its rates in relation to rate adjustments by PG&E. This was discussed somewhat above. CCSF will have to decide whether to make its generation rate changes at the same time as PG&E makes generation rate charge changes, even if its costs change on a different schedule, and how to handle the passthrough of its own cost changes resulting from its suppliers' billing on the same or a different schedule.

2.3 Program Basis Report

The Program Basis Report (PBR) provides an overall view of the program with the express intent of forming the basis for drafting the ESP Request For Proposal (RFP). The PBR will cover all the primary subject areas of the program including basic service, renewable infrastructure and efficiency. Its objective is to define features and design criteria for the detailed technical specifications, for governing body approval, and ultimately for implementation. The PBR will answer the key questions about the program such as:

- Which needs will be met by the ESP and which by existing organizations?
- What will customer service look like?
- How will the top technical issues be solved?
- What does the near- and long-term operating organization look like?
- What is the recommended procurement strategy?
- How will program risks be mitigated?
- How will we measure success?

The actual process of developing the PBR also has a purpose. Employing a disciplined and rigorous process to solicit input from stakeholders achieves the first level of stakeholder buy-in.

2.3.1 Needs Analysis, Stakeholder Surveys And Interviews

To prepare the PBR, the implementing entity needs to identify the key requirements and features across all program functional areas. Territories to be covered include:

- Goals and objectives
- Technical elements
- Customer services
- Stakeholder management
- Commercial and contractual issues
- Public policy
- Program support including training and outreach
- Program management, schedule and phasing

This is a classic needs analysis. The implementing entity should employ two approaches to conducting the needs analysis. On the one hand, it is a straightforward process of tapping internal and external experts to leverage best practices and develop the new, creative elements. On the other hand, there is a survey and interview process conducted with a broad range of stakeholders to make sure their voices are heard and that the program addresses elements seen as key in their eyes. The constituency analysis discussed in the Outreach Section of this plan provides a good resource for determining with stakeholders should be engaged in the PBR process.

2.3.2 Procurement Strategy

The procurement strategy will be developed by building on the information developed through the Program Basis report development process. Each factor developed through this process must be sufficiently addressed in the procurement, and the procurement process itself must provide adequate information, and allow sufficient time, for the ESP bidders to develop complete and responsive proposals.

There are a number of approaches that can be used to conduct a complex procurement, including:

- Single round low-bid
- Single round price and other factors
- Two phase low bid; initial proposals with no pricing, final priced proposals
- Two phase as above, price and other factors
- Negotiated, with Best and Final Offer (BAFO)

The pros, cons and relative timeframes of each possible method will be considered in selecting the procurement strategy, considering the development factors referenced above along with any statutory restrictions or guidelines applicable to the implementing entity.

2.3.3 Program Risk Analysis

The San Francisco CCA Program involves complexity and a number of intergovernmental and business participants. Accordingly, the program needs to be well organized and efficient to ensure that all potential issues are identified well in advance, and addressed in a timely fashion. This effort is one of the key elements in successfully eliminating or mitigating complex program risks. Said another way, in a complex program environment, the application of early proactive efforts to issue identification and resolution should reduce the quantity of problems ultimately faced by the program.

One of the most significant success factors for the CCA Program will be how effectively and fairly risk is allocated between the CCA Program and the ESP, especially for the renewable power generation elements. The CCA Program will need to complete the risk assessment and allocation process prior to finalizing the RFP documents and the ESP Contract terms.

For the CCA Program, there are a range of risk areas that track the program phases. During the Program Development phase, the CCA Program will face risks relating to the process of completing the 'checklist' of necessary steps required to get the program to the point where an RFP for the ESP can be issued. As the implementation phase proceeds, the risks will shift to include the range of risks common to large scale infrastructure projects.

The approach to managing these risks is for the CCA Program staff to identify the risks inherent in each of its activities across the phases of the program, and then to develop effective strategies to eliminate, mitigate or allocate these risks between the CCA Program, the ESP and possibly other stakeholders if appropriate.

It is often tempting for an owner to allocate as much risk as possible to a contractor for various reasons, especially in a performance driven, turnkey or DBOM contracting arrangement. However, there are two main disadvantages to this approach; the likelihood of excessive bid price contingency and a higher likelihood of conflict and claims as the project advances.

Effective risk allocation is the process of determining which party can best manage a given risk by virtue of its strengths and resources. A review of the costs and impacts that may be associated with the risk can be an effective method to test the a choice of a party to manage a given risk. If having that party manage the risk is projected to be the most effective in reducing impact, and containing costs, this confirms that the right party has been selected to manage the risk.

There are three steps that can be used to guide the risk allocation process. The first is to identify the nature of the expected project risks, and determine whether they are 'known' or 'unknown' risks (discussed in further detail below), the second is to assess the relative capabilities of the CCA Program and the ESP to manage or mitigate each of the risks. The third is to determine if risk should be assigned to the CCA Program, the ESP, a third party stakeholder, or shared. If shared, this step includes developing the criteria for sharing the risk.

This plan proposes that a supplier perform a majority of the wholesale electricity business functions required to operate the CCA. For example, the supplier should assume responsibility for daily power operations: scheduling power and settlement with the California ISO. That responsibility will extend to resource procurement risk management and credit management with generators, though the level of that responsibility may be affected by decisions around municipal power plant ownership. The wholesale power responsibilities of the supplier should be guided by resource planning direction provided by the CCA both in the RFP and as necessary with additional interaction with the supplier.

2.3.3.1 Risk Identification

The CCA will first complete a categorical identification of the significant risk factors that will be or are expected to be present as the project is advanced. Once the specific risks have all been identified, the nature of the risks will be determined. A key determinant is whether a risk is 'known' or 'unknown'.

2.3.3.2 Determining The Nature Of The Risks

A 'known' risk is one where the ESP would be in a good position to understand the nature and extent of the risk, and to identify the possible range of its cost impact. A 'known' risk on a lump sum infrastructure project could be a quantity risk taken by the contractor, where the exact quantity of a certain item cannot be determined until construction is in progress, but the upper and lower ranges of required quantities it is predictable. The allocation of this sort of risk to the contractor is commonly used for

many lower cost elements of an infrastructure project, such as routine electrical system or plumbing components.

By contrast, an unknown risk is one where the Contractor must accept responsibility for elements of a project without having complete information. For example, requiring a contractor to excavate a number of sites to build foundations without telling the contractor anything about the ground conditions, or allowing the contractor to perform their own site evaluation presents the contractor with an unknown risk. As should be obvious from this example, this is not an ideal approach, because the contractor will have to include 'worst case' costs in its bid price.

2.3.3.3 *Allocating The Risks*

Once the risks have been identified, the next determination is of whether the CCA Program or the ESP will be in a better primary position to manage each risk as the project proceeds. Generally, those risks that are more toward the 'known' end of the scale, have potentially smaller proportional cost impact relative to the bid price and will be more closely related the ESP's scope of work are better managed by the ESP.

By contrast, the management of the ongoing cooperation required from city agencies is an area where the implementing agency, not the contractor, is in the better position. Accordingly, this is typically the implementing agency's responsibility. Some further examples of risks that are typically allocated to the contractor and the agency in a turnkey project are shown in the following table:

| CONTRACTOR | AGENCY |
|---|--|
| <ul style="list-style-type: none"> ▶ Final design/functionality ▶ Quantity risk to achieve functionality ▶ Longer term quality (if DBOM) ▶ Schedule/completion Time ▶ Cost (inflation/currency) ▶ Procurement ▶ Coordination | <ul style="list-style-type: none"> ▶ Providing access and cooperation at all project site locations on time ▶ Input/changes from Service Providers ▶ Community/political input ▶ Force Majeure events ▶ Changed site conditions ▶ Changes in regulations |

2.3.4 Risk Sharing

Many project risks are predictable and incremental. This means that if the most likely predicted outcome for a risk element is given an arbitrary value of 100%, it is more likely that the actual experience will be a result closer to the predicted 100% than a result that varies widely from the predicted outcome. Accordingly, an owner can reduce ultimate costs by taking the responsibility for less likely, worst case scenarios.

As certain incremental risks can have significant costs, the CCA Program may benefit from a risk sharing approach for some elements of the renewable infrastructure risks to prevent excessive contingency pricing. A typical risk sharing structure for incremental risks is to include a set of tiers in the contract pricing structure. The first tier is the lump sum price; up to a certain threshold, all costs associated with this element of risk are the contractor's responsibility. Above the first threshold, there can be some shared tiers where contractor and the agency are each responsible for set percentages of the costs, and then the CCA Program would take full responsibility at the higher threshold level, which has a lower probability of being reached.

The selection of the actual thresholds and percentage amounts is critical in whether or not this approach will succeed on any given project. The first challenge is to make sure that it ends up functioning as a risk mitigation structure, and not as a bonus pool for the contractor. The key to this is to ensure that the ESP bears more of the initial risk through the tiers, with the CCA Program's responsibilities phasing in at the higher end, to 'cap' the risk. The idea is to structure a hurdle of ESP risk between the lump sum price and the tier(s) where the CCA Program pays most of the costs.

In conclusion on risk allocation, effective analysis of the potential risk factors, and strategic allocation based on the best approach to managing the risk should allow the ESP bidders to more accurately assess the amount of contingency funding to include in their pricing for the risks they will be assigned under the contract. Once the allocation has been determined, it is important for the CCA to work closely with the ESP bidders to make sure that they understand both the extent of the risks that they will be responsible for, and any limitations on this risk that will work to protect them. This communication process is beneficial, because when contractors fully understand the risks they will be responsible for, they are less likely to assert claims based on incorrect or incomplete understandings of these risks as the project proceeds.

At the point of implementation, large infrastructure programs often include a pilot phase. A limited deployment of the ultimate installation, or pilot, carries with it advantages and disadvantages, some of which are identified in Exhibit V-1.

Exhibit V-1 Pilot Considerations

| ADVANTAGES | DISADVANTAGES |
|---|--|
| <ul style="list-style-type: none"> ▶ Evaluate system performance and customer experience and make adjustments prior to full roll-out ▶ Limit risk of large scale failure or issues ▶ Gain incremental stakeholder support as a step toward full roll-out ▶ Create a internal performance incentives for system provider to do the right thing or risk not progressing to full roll-out ▶ Gain working knowledge of new processes required by city departments (e.g., permitting) | <ul style="list-style-type: none"> ▶ May increase ultimate cost of the program ▶ Risk losing momentum on full program because resources and stakeholders focus only on the pilot ▶ Increases overall schedule |

Because the City has already conducted related programs in various forms, including solar installation on Moscone Center and the Generation Solar program, the City has already realized many of the typical benefits of pilot programs. These programs in particular have provided valuable insight into the solar program elements including some experience with customer perspectives, contracting, permitting and financing solar installations as well as experience with the technology itself. As such, the City has little more to gain from additional pilots and should move forward with the largest initial implementation feasible. See Section 2.3.4.1 “Generation Solar” below for further description of the Generation Solar program.

In any case, pilot or not, it is necessary to stage implementation in manageable phases. The nature of this program lends itself to a logical phasing at the highest level. Initial “Basic Service” without a significant renewable or efficiency component can start shortly after ESP is selected. The efficiency components can be ramped up rapidly with an ongoing component that can run in parallel with the renewable program elements. Wind, solar and distributed generation (DG) each flow to a logical timeline with DG being the quickest to design and implement, wind following next, and then followed by in-city solar which is most complex and requires the longest timeframe. Within each of these renewable elements, there will again be a logical phasing that the implementing entity will need to detail out with the selected ESP.

2.3.4.1 *Generation Solar Pilot*

In order for the City and County to prepare capacity for administering its Energy Independence Ordinance, the Board of Supervisors approved an ordinance 270-03 (Ammiano, November 5, 2003, signed by Mayor Willie Nelson Jr. December 5, 2003) creating a Generation Solar program in San Francisco. This ordinance provided that, not later than August 1, 2003, the SFPUC and the Department of the Environment, in consultation with the City Attorney, the Mayor's Office of Public Finance, the Department of Building Inspection and the Planning Department, should provide the Board of Supervisors with a plan and budget for implementing a solar pilot program serving 100 residential and commercial properties in San Francisco, including, but not limited to, the following:

- (a) An executed inter-departmental memorandum of understanding delineating the roles, responsibilities and respective budgets of each department to deliver the program;
- (b) A marketing plan to enlist program participants utilizing City resources that may include the City's website, public service announcements on buses and in bus shelters, signs at libraries and recreation centers, utility bills, tax notices, voter handbook mailings, Citywatch, etc.;
- (c) Financing options for residential and commercial building owners, including self-financing, financing arranged by or through the City and backed by lease payments from property owners, and assistance applying for state and federal subsidies and/or tax credits;
- (d) Proposed changes to the San Francisco Building and Planning codes and Department of Building Inspection and Planning Department procedures necessary to expedite permitting, reduce permit fees, and protect access to sunlight for solar investments;
- (e) A proposed methodology for screening and prioritizing pilot program applicants;
- (f) A list of interested residential and commercial building owners obtained by implementing the marketing plan;
- (g) A database for program applicants including those not selected for the pilot program;
- (h) Proposals for negotiating and executing grid inter-connection agreements with PG&E where necessary;
- (i) A proposed apprenticeship training program for solar installers and maintenance personnel, developed in consultation with City College and affected unions, including but not limited to, IBEW Local #6, IBEW Local #1245 and the San Francisco Building Trades Council; and

- (j) Proposed criteria for evaluating the success of the residential and commercial solar pilot program.

The Generation Solar Ordinance provided that, not later than September 1, 2003, the Public Utilities Commission and the Department of the Environment should provide the Board of Supervisors with a Generation Solar implementation plan and proposed Request for Proposals for use by respondents in submitting proposals to implement a residential and commercial pilot solar program serving at least 100 residential and commercial buildings. The RFP should request, at a minimum, the following from respondents:

- (a) A range of photovoltaic technology options and a range of additional conservation and energy-efficiency improvements to reduce on-site electric loads for residential and commercial properties hosting solar photovoltaic installations;
- (b) Standard system designs for the following:
 - (1) Installations for existing residential homes;
 - (2) Installations for existing apartment buildings, including proposals for how to manage metering for separately metered apartments;
 - (3) Installations for existing commercial and industrial buildings; and,
- (c) Information related to system warranties and insurance requirements;
- (d) Proposals for contract monitoring by the City, remote system monitoring by the City, maintenance contracts, and schedules for implementation;
- (e) Financing proposals including, but not limited to, self-financing by building owners and City financing repaid by monthly lease payments (including procedures to collect delinquent payments);
- (f) Proposals for how the City can best assist with marketing of the program;
- (g) A methodology for analyzing solar exposure, peak shaving potential, and energy-efficiency savings potential at candidate sites;
- (h) Technical assistance for such applicants who wish to proceed with solar installations and energy conservation improvements on their own; and
- (i) Any other requirements that the Public Utilities Commission and the Department of the Environment deem necessary.

Finally, Ordinance 270-03 provided that, not later than twelve months after launching the program, the Public Utilities Commission and the Department of the Environment shall present to the Board of Supervisors necessary to implement subsequent phases of San Francisco's solar program:

- (a) A plan to pursue bond agency ratings for the Hetch Hetchy enterprise of the Public Utilities Commission;

- (b) Calculations and documentation of the energy subsidies provided to General Fund departments and other City agencies;
- (c) Recommendations to the Board of Supervisors for establishing energy rates that will lead to higher bond ratings;
- (d) A plan to develop bond pro formas, developed in conjunction with the Mayor's Office of Public Finance, necessary to issue bonds to finance future solar program expansion

The City and County has launched, and is now implementing, Generation Solar, preparing City and County agencies to facilitate an orderly and successful implementation of the Energy Independence ordinance, for which this Implementation Plan was prepared and adopted, in particularly the three (3) year rollout of its 360 MW infrastructure.

2.4 Property/Siting

In order to advance the installation of the renewable energy components, the CCA Program must secure access to appropriate sites, and the rights required to install the equipment. This process could take a number of forms, depending on how certain elements of the CCA Program are structured, and also on the form of ownership for any given site.

A wide range of commercial terms could be appropriate, ranging from situations where the CCA is compensated for placing the equipment to instances where property owners grant these rights at no cost in return for some of the power generated, to instances where the CCA Program provides some form of compensation in order to use an especially suitable site. And, regardless of the commercial terms, it is expected that more complex agreements will be necessary to secure the required rights for installations where the site is owned by a business, or a governmental entity.

The first step in property rights acquisition is a site selection process. The site selection process must be structured to ensure that the renewable power generation equipment is allocated in an equitable and unbiased manner, and does not favor one class of ratepayers over another. The site selection process will be followed by property rights negotiation, and once the rights have been secured, the management of the property rights.

2.4.1 Site Selection Process

The first step of the site selection process will be to identify the larger range of potentially suitable locations for the installation of renewable power generation

equipment. Ratepayer data from PG&E will be used to develop the list of potential customers for on-site installation. This data would be transferred to property maps to identify the broader range of potential sites for the installation of the required renewable power generation equipment.

In parallel, a public information process will be conducted to advise property owners how the CCA Program works, and that property owners will be able to have renewable power generation equipment installed on their property, through a selection process. It will inform them of what the process would entail from their perspective should they choose to participate. It will also identify the agreement terms for property owners who wish to have renewable power generation equipment installed on their property.

It is expected that, from both the CCA Program perspective in terms of procedure, and from the property owner's perspective, the process would be quite different for different types of property owners. For example, both the rights agreement and installation process would be significantly different for a single family home and a building owned by a large national business. The public information process will provide detailed information describing both the installation and longer term power generation and use processes for the different types of property owners expected to participate.

Following the public information process, interested property owners will be able to participate in the site selection process. All of the sites for the generation of renewable power that can be wheeled will be selected on a combination of structural suitability, site cost relative to the expected power output, and the site's power generation capability, using weather, light, wind and other data as appropriate.

The sites for the generation of renewable power that cannot be wheeled must be based on an equitable process to ensure that the benefits of this equipment are shared among all participating ratepayers. A range of methods can be used to ensure this outcome.

2.4.2 Property Rights Negotiation

Once sufficient sites have been identified to allow for attrition, the work to secure the required access rights would begin. Obtaining the required property access rights for the installation of the renewable power generation infrastructure could be one of the more demanding elements of the CCA Program. The challenges include the time required to securing the access agreements, the wide variety of both the physical locations and the types of property ownership. Working with these variables, it is likely that a variety of forms of agreement would be required.

A number of policy decisions relative to the actual approach to securing the site locations would be required during the Program Definition phase. Some of the policy areas to be defined are:

- (a) What terms would the CCA Program be able to offer property owners? As incentives to participate in the program, and in terms of protections for the owners and their properties?
- (b) What 'rights' approach would be used to secure the necessary agreements? Would the CCA Program be able to or want to acquire ownership of certain properties if necessary?
- (c) What role will the ESP play in the site selection process?
- (d) Could property owners be compensated for access, or would an offset agreement be used based on their power consumption?
- (e) Who would own the renewable power generation equipment?
- (f) What entity would be responsible for negotiating the agreements?

These and other related questions would need to be addressed in order to develop the approach to securing the property rights necessary for the installation of the renewable power generating equipment. And the development of the approaches to be used will in turn dictate a range of related elements, such as the expected pace of the rights acquisitions, the structure of the staff responsible for property, and the budgets needed.

The renewable power generation infrastructure equipment will be located both in and outside of city limits. The sites selected for installation will likely have a range of ownership, including individual, small business, large business, and governmental ownership. Some of the sites, and decisions relating to use of the sites could be controlled by long term lessees, or multiple lessees. In some instances, it may be preferable to acquire a site outright, and in other instances, a long term lease agreement may be needed. Permanent or construction easements for access to the installation part of a site may also be needed.

In order to secure the desired access rights, a number of factors relative to the installation and long term maintenance of the renewable power generation infrastructure equipment will need to be covered in the agreements with the property owners. For example, the owners may want to impose certain limitations on the intrusive effects of installation, such as limitations on hours worked, noise and dust, etc.

And also, Owners may request guarantees and recourse methods relative to any negative physical effects of installation on the building; either during installation or if latent defects in installation end up resulting in leaks or other problems.

2.4.3 Site Management

Once the property rights for sites have been secured, the next range of activities follow from the nature of the rights, both during the implementation phase, and into the Operations and Maintenance Phase. During the implementation phase, the implementing entity must take all agreed steps to maintain the access as per the access agreement. All collateral responsibilities, such as listing the property with the CCA's insurance providers, must be attended to.

If the site is to be leased, payments need to be made, and any conditions reflected in the agreement must be adhered to. For example, if the CCA Program agreed to cover the cost of a structural inspection by an inspector of an owner's choice, the process for arranging and paying for the inspection must be conducted. If a site is to be purchased, the CCA Program must ensure that all elements of the transaction are carefully tracked, to ensure that the property transaction has been fully completed, all payments have been made, all required insurance is in place, etc. before any installation work proceeds.

The implementing entity must also ensure that its rights are preserved if changes in the ownership of a property occur at any point in the process. Obviously, provisions to this effect will be included in all original agreements, but there will likely be instances where a new owner is either not fully aware of or willing to comply with the original terms, requiring further resolution.

As the Program advances, a longer term property management effort will be required to address all property responsibilities and issues. Are all required payments being made for each site (lease, fees, permits, etc.)? Is the CCA Program maintaining ongoing compliance with all of its obligations relative to each site? The CCA Program will need to develop procedures and apply staff resources to ensure that it manages all of its property related responsibilities effectively.

2.5 Associated Governmental Process

The CCA Program will involve a number of other governmental entities as it is implemented. Examples of the processes involving other governmental agencies include obtaining permits to using sites owned by other governmental agencies to securing any benefits available through governmental clean power and efficiency programs. In addition to formal involvement, the CCA will be a high visibility

program, and as such, it will benefit the program to build and maintain political support.

In order to effectively manage all required governmental involvement, the CCA Program will first work to identify all of the City, State and Federal governmental agencies that will be involved by the nature of their jurisdictions. This will include all agencies that will need to provide any form of permits or other forms of approval for the CCA Program to advance, as well as agencies that have oversight roles. It will also include descriptions of all interface responsibilities that the CCA Program and the involved agency will have during the implementation and subsequent operation of the CCA Program.

It is expected that the main areas of intergovernmental involvement will relate to the establishment of a CCA, to the rate setting and related customer protection measures, and to the environmental and other land use regulations that may be involved in the installation of the renewable power generation infrastructure.

When all of the CCA Program's intergovernmental responsibilities have been identified, a schedule of required CCA activities will be developed to support the overall timing requirements of the program. Depending on the volume, nature and skill sets required, appropriate staff resources will be assigned to address the CCA's intergovernmental responsibilities.

The previous work in San Francisco to install solar power generation equipment at the Moscone Center and the Generation Solar program have served to familiarize and prepare affected City agencies for working with renewable power technology installation. It is expected that the CCA Program will benefit from progress made through these efforts.

In addition to intergovernmental responsibilities that the CCA Program will have, it may also be able to benefit from other governmental activities. A number of governmental agencies have ongoing programs in clean energy and conservation. From acquiring specific technology assistance or equipment, to participating in emissions trading, to gaining the benefits of research, there may be significant benefits to the CCA Program available through other complementary governmental agency efforts.

The CCA Program will first categorically identify all such complementary programs, and the specific benefits they make available. Then, depending on the nature of activities required to secure these benefits, appropriate staff will be assigned to coordinate the CCA Program's efforts to participate with these complementary governmental agency programs.

2.5.1 Methods for Entering and Terminating Agreements

This section should describe the process by which customers agree to take service from the CCA, and the process by which customers may terminate service, except as may be provided in utility tariffs.

Customers shall take service on an opt-out basis after an ordinance is adopted by the City and County awarding contract to the City and County's chosen ESP, with two customer notifications from the City and County of San Francisco in regularly scheduled PG&E monthly electric bills over a 60 day period prior to transfer of participating customers onto the new service, and two more notifications over 60 days in the next two regularly scheduled monthly electric bills, as described in this Implementation Plan:

Opt-out notifications shall present the City and County's new proposed service in a transparent comparison of terms and conditions of service before and after switching to the City and County's chosen new service on the last day of the 120-day opt out period, such that a consumer can easily compare the prices (which are not subject to a Commission rate increase) and resource portfolio of the CCA service and the prices (informing the customer of the possibility of a rate increase by the Commission) and resource portfolio (percentages of RPS compliant resources for utilities under state law vs. for the CCA under its 51% rate schedule, and a comparison of the difference between an RPS based on purchased green power transmitted from areas remote from the customer, versus a "hard" RPS based on new resources built near to the customer.

If a customer chooses to opt-out during this period by checking and returning the postage paid detachable opt-out card to the City and County, under law, there shall be no charge to that customer by any party, PG&E or San Francisco for electing to opt-out. As with PG&E, customers may obviously relocate from San Francisco and leave its service as a result, without any charge for leaving the CCA's purchasing contract with the ESP. After a new resident or business comes to San Francisco, they will be given the opportunity to opt-out before being enrolled in the City and County's CCA program.

Under state law, those residential or business customers who do not elect to opt-out of the City and County's CCA program may aggregate their loads through a public process with Community Choice Aggregators, if each customer is given an opportunity to opt-out of their community's aggregation program. This shall consist of the opportunity to opt-out placed in regularly scheduled monthly PG&E electric bills, using an inserted single page double-sided form with a detachable postage paid postcard with a simple opt-out checkbox, once a month over four months or 120 days.

The Board of Supervisors shall enter into agreements with its chosen ESP by ordinance, and any termination of such agreement shall also be undertaken by ordinance. The City and County is limiting its contract offer to registered Electric Service Providers relating to energy purchases or sales. These contracts will consist of a formal agreement delineating purchase and service responsibilities (The California Municipal Law Handbook, p.IV-76 (2002 ed.)). The date of termination of this agreement shall be at least seven years from the date on which its service commences, but could be as long as fifteen years, and may be extended by adoption of an ordinance in order to facilitate a Phase II and/or Phase III H Bond issuance to complete the 51% "hard" RPS by 2017, as determined by the Board of Supervisors.

Ordinance 86-04 provides that the ESP shall transfer ownership, upon termination of a CCA ESP agreement, of all online and functional H Bond financed renewable energy, energy efficiency or facilities to the City and County.

2.6 ESP RFP

The effectiveness of the process used for the selection of the CCA ESP will be one of the critical factors in the success of the overall program for a number of reasons. First, the procurement process must have a successful pre-qualification process, to involve the best potential ESP bidders. Second, the procurement process must be well structured, and then managed within the structure, to help reduce the possibility of bid protests. Third, the bid documents and contract must successfully and completely define the responsibilities expected of the ESP. Fourth, the bid documents and contract must be clear, complete and fair, to minimize the addition of contingency pricing.

The RFP sets the stage for the partitioning of risk between the winning bidder and CCSF in the contract. One crucial factor in designing an RFP is to set the supplier incentives to fulfill the CCA goals (e.g., a shared savings/losses approach with a wholesale supplier might set the right incentives for aggressive supply contracting.)

2.6.1 Pre-Qualification Process

Because of the complex nature of the ESP's role, it will be important to structure a pre-qualification process that on one hand ensures that a wide range of potential ESP's are informed of the upcoming ESP procurement, and on the other hand, is effective in eliminating teams that do not have sufficient resources and capabilities to successfully fulfill the responsibilities assigned to the ESP.

The San Francisco CCA program is a pioneering effort in that it combines elements and scale that have not been addressed in a U.S. CCA Program. The ESP will need to perform a number of functions, comply with a number of complex regulations, and take responsibility for designing, building, operating, and maintaining a renewable energy power generation facility. Accordingly, each ESP bidder will likely consist of a team of firms, combining their efforts to address these obligations.

While the ESP bidder teams will need to have strong financial capabilities on a team-wide basis, it will be especially important for the CCA Program to develop ‘filtering’ criteria appropriate to ensure that smaller, well qualified firms can be part of an ESP team. A number of other specific qualification criteria geared toward the CCA Program will only be able to be developed on the basis of the information developed through the Program Development Phase.

For example, the development of the technical requirements for the renewable power generation equipment may raise the issue of whether exclusivity provisions should be applied to suppliers. If there are specialty firms whose unique products would be beneficial to the CCA Program, it would be better to allow these suppliers to be available to participate on more than one ESP team.

When the criteria for qualification as an ESP have been set based on the criteria and role for the ESP developed during the Program Development Phase, the CCA Program will develop the Request for Qualifications document. Through public advertising and targeted notifications, the CCA Program will conduct outreach efforts to inform available bidders of the opportunity to qualify to bid for the CCA ESP Contract. When the qualification packages are received, the CCA Program will conduct the evaluation process to determine which ESP bidders will qualify to receive the RFP.

2.6.2 Procurement Process

There are two important factors in the management of the CCA ESP procurement process; the development of clear, complete descriptions of the steps and schedule of the ESP procurement process, and then, as much as possible, sticking very closely to them. The schedule, events such as pre-bid conferences, process such as the written requests for information and clarification process, the addendum process will all be well defined.

In light of the complexity of the CCA Program, there will be an interactive process to communicate critical program information to the potential bidders. Complex projects are generally more successful if bidders are more involved in the bid process from the outset, and are requested to provide constructive feedback on the RFP documents.

While the RFQ, RFP and other project documents are the primary forms of information exchange, this additional effort on the part of the CCA Program is likely to result in better quality bids.

2.6.3 RFP Documents

The CCA RFP documents will be developed to achieve the following quality standards: completeness, consistency and lack of internal conflict. The release of poor quality RFP documents is likely to ultimately have far more serious schedule and cost impacts to the CCA Program after the ESP contract is awarded than the extra time and effort it would have taken to improve the documents prior to issuance.

Completeness includes the process of ‘designing’ each document’s content prior to drafting it to ensure that it will cover the required subjects, and later, confirming that all required content was in fact completed, and working to eliminate all gaps, missing appendices, attachments, forms, etc.

Consistency applies to the use of terminology, and to the structure of the document, especially to coordination of sections and cross references. To the greatest extent possible, the CCA Program team will work to develop defined terms, and use them consistently. Also, the documents will be cross checked near the end of the development cycle to ensure that related sections actually complement each other, that there are no conflicts in different provisions that apply to the same subjects, and that the cross references all check out.

The CCA Program ESP RFP will consist of the following types of documents:

- Instructions to Proposers
- ESP Contract
- Technical Specifications
- Applicable Studies and Data

2.6.3.1 *Instructions to Proposers*

This document will provide all information necessary for bidders to understand how to respond to the RFP. This includes the ESP scope elements that the bidders must address, the bid cycle schedule, the evaluation criteria, the bonding or other financial assurance requirements, and all of the pricing and rate design forms.

It will also provide the schedule for all pre-bid information sessions, and descriptions of the subjects to be covered, the rules applicable to the process, the formal process by

which bidders can request clarification or ask questions, and the process for the CCA Program to issue addenda.

It will describe the bid submittal content requirements (such as a bid bond, addenda acknowledgement sheets, proof of insurance, escrowed bid documents, etc.). It will also describe the bid opening process, the process for verification of the validity of the apparent selected bidder, and the process for contract execution.

2.6.3.2 ESP Contract

The ESP contract will include all elements of the ESP's responsibilities, as further developed during the Program Development Phase. It will also include the Design, Build, Operate, Maintain (DBOM) provisions for the renewable infrastructure element of the CCA Program. The contract will include a number of commercial elements, such as the payment provisions, provisions relating to the use of the H Bonds and cash flow, completion dates for all infrastructure phases, the ongoing insurance and bonding requirements, termination and warranty provisions. It will also include all requirements during the Operations and Maintenance phase, including customer service requirements and standards for the performance of required maintenance.

Long-term savings from the program shall be used to offset higher start-up costs, offering participating ratepayers economic benefits of 51% physical energy independence by 2017 without a rate increase, as well as fixed, hedged or tagged rates for both residents and businesses, which PG&E cannot offer its customers, according to the ESP's agreement with the City and County.

The contract will also contain provisions for the conditional extension of the infrastructure elements of the program if the ESP has been successful in meeting rigorous performance standards applied in the contract. The City's authority to issue Proposition H bonds is not limited to the renewable infrastructure elements required under Ordinance 86-04. If the CCA Program (including repayment of the first set of Proposition H bonds) is successful, another set of renewable power generation infrastructure elements can be initiated.

2.6.3.3 Technical Specifications

This document will provide the technical and performance standards for the renewable energy generating equipment, and for conservation and efficiency technology. It will cover all design and installation requirements. It will include all quality and durability

requirements, and address compliance with all codes, environmental regulations and other industry standards.

2.6.3.4 Applicable Studies And Data

All applicable data that has either been collected by the CCA Program or developed during the Program Development Phase will be provided. This may include PG&E ratepayer data and power consumption data, (screened and redacted as appropriate to preserve confidentiality), site location data, conservation and efficiency data.

3.0 Procurement

The CCA Program will need to have a number of major program elements in place prior to actually initiating the procurement. These will be defined more fully during the Program Development Phase, and will likely include: having the Revenue Bond issue structure in place, having all required major permits for the renewable power infrastructure, etc.

Once these elements are in place, and the RFP is issued, the CCA Program will conduct the procurement process, following the procedures described in the Instructions to Proposers document. This will include preparing for one or more pre-proposal conferences as appropriate, developing and issuing responses to all formal requests for clarification and questions, preparing and issuing any necessary addenda.

The procedures for reviewing technical proposals will include an initial review for completeness and responsiveness. For all proposals that have been determined to be conforming, an the CCA Citizen's Advisory Task Force will evaluate and score the proposals in accordance with the evaluation criteria. Then, the price proposals will be opened publicly, the scores totaled and a report of the Task Force's findings submitted to the Board of Supervisors which shall select the chose ESP, if any.

The apparent winner's bid will be reviewed to confirm validity, that all required submittals have been included (such as the bid bond) and that the pricing does not contain any significant errors. If the apparent winner is confirmed, then this bidder will be invited to enter negotiations (if the process is negotiated), or to provide the submittals necessary for contract award, such as the payment and performance bonds. When the CCA Program has secured approval from the Board of Supervisors, the contract will be executed.

The award of the contract will initiate the Implementation Phase. Depending on the Program's cash flow requirements, the first or subsequent Revenue Bond will be issued.

4.0 Implementation

The implementation phase as discussed in this section starts upon Notice to Proceed to the ESP and continues to the point where operations begin. As generally described in Section IV-1 "Overall Program Schedule," there are three main tracks upon which the implementation proceeds in parallel.

The first track is that of Basic Service. This includes the customer outreach process, and leads to the point where the ESP takes over electricity supply to all customers except

those who have opted-out of CCA. This track has a very short design phase, which is primarily focused around the seamless transition of customers. The major design elements of this track include commercial arrangements such as contracting to supply power to CCA customers, wheeling, billing arrangements and customer service provisions. The time between design and implementation on this track is short, only a matter of weeks, and it is driven largely by the statutory opt-out period.

The second track is that of energy efficiency and conservation. In this track, the ESP takes on the design and implementation of the efficiency and conservation mechanisms.

Although the design and implementation of this track stretches over a longer period, there is ultimately only a very limited “operational” element.

The third track is that of renewable infrastructure implementation. This track is primarily that of a large capital infrastructure project. It has the most complex implementation phase and its sub-phases are identified and described in the subsequent sections.

4.1 Program Management

Overall project management is the responsibility of the implementing entity and covers a number of activities including:

- Defining and prioritizing program activities
- Monitoring progress of tasks against the project schedule
- Identifying, analyzing and negotiating changes to contract and/or schedule
- Determining impacts and preparing cost estimates for changes
- Monitoring budgets and implementing cost containment strategies
- Verifying, evaluating, and negotiating invoices
- Preparing and progress and issues reports – covering technical, financial, contractual subjects
- Identifying, tracking and resolving project issues
- Preparing and distributing project information
- Maintaining a communications tracking system, for all formal and informal communications to and from ESP and other stakeholders

4.2 Outreach

A main purpose of the Outreach effort is to create a widespread positive perception among the individual and business customers that the CCA is being implemented with the main purpose of benefiting and protecting the City's electricity customers. It also will include the process for informing customers of their right to opt out of the CCA Program, and provide the process for opting out, in full compliance with the provisions of AB 117 and Ordinance 86-04.

The core customer groups are the traditionally defined residential, commercial and industrial ratepayers. It is also recognized that a small group of business customers represent a large portion of the overall power load, and thus are important participants in the CCA. Because of the importance of their participation, additional outreach will be conducted to inform these customers of the benefits of the CCA Program.

Beyond these core customers, there is a wide and diverse set of stakeholders with varying levels of program interest and communication needs. The stakeholders range from the site owners of renewable infrastructure elements to various city agencies, regulators and the private sector. A comprehensive outreach program recognizes all stakeholders.

CCSF businesses and organizations that are not served by PG&E today will not become CCA customers unless they opt-in with CCSF's consent. This category of customers includes BART, and existing Direct Access (DA) customers. A key strategic decision for CCSF will be whether to attempt to recruit existing DA customers whose high electricity usage may help to lower power costs for all CCA customers.

The term stakeholder generally carries a positive, or at least neutral, connotation with regard to the stakeholder's view of a program. There is however, an important subgroup of negatively inclined stakeholders who have a vested interest in the status quo and vigorously defend against any change. The CCA's outreach program will acknowledge this subgroup and contain specific processes and mechanisms to address them.

The approach to establishing communications goals and their supporting messages includes:

- Identifying stakeholder audiences and the most effective vehicles/messages to reach them
 - Conduct stakeholder analysis: identify who to focus on and why
 - Identify the appropriate vehicles and channels for each stakeholder group

- Develop appropriate messages for each stakeholder group and assess the level of effort in tailoring the messages accordingly
- Outline a specific plan to implement communications activities. The plan will be a “living” document so that its tactical approach can be adjusted as the project evolves. It will include items such as:
 - Timing and key milestones
 - Stakeholder pulse checks
 - Feedback approach
- Define reasonable measures of performance for the communications goals

Although no market research has yet been conducted about customer response to potential products and services offering from a CCA in CCSF, basic customer demographics and energy usage patterns are available. Notably about 25% of larger business customer electric load in CCSF is currently served through DA - this equates to about 12% of the total potential CCA load. These accounts, some of the largest electricity consumers in the city, will not be automatically enrolled in the CCA and will have to be recruited upon the expiration of their contracts if the CCA wishes to do so. This might be worthwhile since large business customers offer a significant revenue base and often have electricity usage profiles that are flatter than average. Flatter profiles can potentially lead to lower costs to serve those customers and if their flatter profile helps to flatten out the average CCA profile, this may reduce electricity costs for all customers. **However it is the higher revenues available from CCA large business customers that are the most important consequence of their decisions to opt-out or choose CCA.** In addition maintaining a diversity of CCA customers will help reduce the regulatory risk of the CPUC advantaging any particular customer class in its PG&E rate design proceedings.

Estimated Generation Revenues By Customer Class

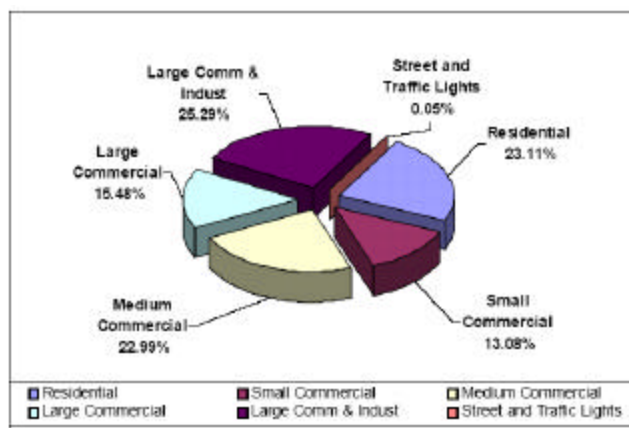


Chart 2 above demonstrates the importance of large customers who comprise about 64% of the potential CCA revenues but only comprise a little over 1% of potential CCA accounts. CCSF residential customers also consume a smaller proportion of electricity in the higher consumption tiers 3, 4, and 5 than the PG&E average. This is important since PG&E electric generation rates for these tiers are far higher than the Tier 1 and 2 rate levels. Opt-out of CCA residential customers who consistently take power in tiers 3, 4 and 5 could also adversely impact the overall economics of CCA. It is important to recognize that the generation portion of electricity delivery costs varies significantly among customer classes and therefore the impact of higher than PG&E generation rates on customer's bills will also vary. For example for the average CCSF residential customer the generation portion of the electricity bill is about 35%, whereas for the largest commercial customers the generation portion of the bill is about 65%. Hence the city should anticipate that large commercial customers would pay particular attention to the rates offered by CCA.

Although legislative activity to reopen DA to new customers has occurred in both of the last two years, today DA remains suspended for new customers. Current DA customers may continue on that service, but customers who did not have DA contracts by 9/20/2001 may not choose DA service at this time. Current DA customers returning to bundled PG&E service must provide six months of advance notice and, once returned, must take utility service for at least three years. Thus, in order to prevent a customer who might be attractive for CCSF from choosing utility service upon their DA contract expiration, a CCA marketing team would have to identify attractive customers and recruit them to CCA service in advance of the expiration of their DA contract.

4.2.1. Balancing Seamless Operations With Program Visibility

The old adage “all press is good press” does not hold true for a program that will touch the daily lives of all participants by delivering a commodity fundamental to the functioning of modern society. Front page newspaper stories describing program failings need to be more than avoided, they need to be prevented through the combination of the program would certainly not be a good thing. From a customer perspective, the CCA program should be operationally seamless and undetectable. There can be no electrical service interruptions, no customer service interruptions, and no billing problems. Rates must meet or beat existing rates. In many respects, implementing the CCA program without a single customer noticing would be a great success.

While a level of “invisibility” is the goal on the basic operational front, other elements of the program need visibility. In particular, the implementing entity needs to communicate around program identity and the regulatory elements. Positive messages to reinforce local control, reliability and clean energy, as well as general public education of the program, need to find their way to stakeholders.

In addition to traditional channels, the CCA outreach can take on a creative flavor because of the generally positive public response to cleaner technology. For example, a citywide “clean meter” could be provided on a CCA website, which would which would show the current program-to-date kilowatt hours provided from renewable sources. A similar large scale ‘meter’ could be located in one or more public spaces. On the regulatory front, communications concerning opt-out, rate setting disclosure and due process need to reach appropriate audiences.

4.2.1. Communications Plan

The CCA will develop a Communications Plan that ties all the outreach elements together. Developing the plan begins with an iterative process of constituent analysis and outreach goal-setting. The plan recognizes some key factors:

- People are naturally resistant to change
- Communications need to reach a multicultural community
- The customer base contains a wide range of entities, from individuals to businesses to governmental and non-governmental organizations
- The CCA program identity and image should portray the ratepayers as the ultimate winner
- The CCA program identity and image should be established earlier rather than later in the project

The implementing entity should commence outreach work early on in the process, as policy decisions and public opinion are often shaped by feedback from the success or failures of initial outreach.

The primary goals of the Communications Plan are to achieve a broad sense of community ownership of the new CCA program, prepare customers for the inevitable changes that will come with the migration to a new way of receiving electricity, anticipate public information needs and develop material that make the program easy to understand, and ensure that emphasis is placed upon special market segments such as low-income and non-English-speaking customers.

After clearly defining goals for the CCA program and for outreach efforts, it is important to know what to monitor and track to measure the progress toward these goals. Program goals and outreach goals are intertwined. Success at the program level is the ultimate end and the outreach efforts help achieve that success. The Communications Plan must set out the metrics to measure progress and assign resources to monitor and track them.

The Communications Plan addresses both proactive and reactive communications. This section primarily focus on the proactive elements, although many of the same channels and strategies can be applied to reactive or responsive outreach. A closely related topic, that of Crisis Planning, is not covered here, but would have a communications component as a critical part and will need to be addressed in the requirements of the ESP RFP.

4.2.1.2 Outreach Channels

Depending on the program phase, the types of outreach and the lead for those outreach efforts may vary. During the Start-up, Program Definition and Procurement phases, the implementing entity will define and run all outreach efforts. Once the ESP is selected, outreach efforts become a joint initiative between the implementing entity and the ESP. Finally, in the operations and maintenance phases the ESP and the long-term CCA organization run the outreach program. Regardless of who is leading the Communications Plan activities, the following channels can support outreach efforts:

Public Meetings—Public meetings serve a dual function. These gatherings provide an opportunity for the public to learn about upcoming activities and changes and allow the implementing entity to help customers plan for these changes in order to retain their support. Additionally, promotion of the meetings is an excellent way to interest community leaders, the media and the broader public in the CCA initiative.

Stakeholder Forums— Intergovernmental forums (e.g., Chamber of Commerce), advisory groups, grassroots organizations, professional associations with relevant constituents and local and county-level forums already in existence can service as immediate channels for communicating information at every phase of this effort.

Local Events—An annual event plan identifying opportunities to demonstrate renewable and efficiency elements, such as participating in local college and community events using a booth with technology prominently featured, affords a low-cost venue to disseminate project information to a wide audience.

Direct Mailers/Grocery Bags/Utility Bill Inserts—Beyond the required insert notices, alternative methods of educating the public about the CCA Program include these types of outreach. While direct mail may be cost-prohibitive, other alternatives are cost-effective and can reach targeted audiences with minimal effort.

Public Repositories—A list of public buildings, offices, and stores that could serve as repositories of project information is a valuable asset. Promotional posters along with other informational materials that have been developed could be used at these sites. Local libraries and government offices are ideal locations.

City Publications—City agency public information offices can disseminate information for inclusion in monthly internal/external publications.

Telephone Information Center—This call-in number would have pre-recorded information, updated regularly.

4.2.1.2 Press Outreach

A credible program—one that clearly represents the public interest and that has a clear and measurable goal—will generate news. This important premise guides all aspects of successful press outreach. Activities leading to successful press outreach include:

- Develop a media training session for prospective project spokespersons
- Coordinate, as needed, with the City and County officials to time releases, and to forewarn officials of a possibly controversial news item (i.e., schedule delay, technology breakdown)
- Prepare a comprehensive media presentation package. The materials will include a brief, straightforward background sheet, project fact sheets, brochures, photographs for print, stock video footage for

- broadcast, profiles on key project representatives, and copies of current news releases
- Schedule information meetings with key editorial and assignment staff from all newspapers, radio, and television stations in the region
 - Schedule guest appearances for project representatives or notable authorities on public affairs programs to keep the public informed of the project's progress
 - Inform the media of any workshops or presentations by key figures involved in the project
 - Draft periodic news releases updating media outlets of project progress
 - Draft occasional feature articles about key milestones in the project
 - Continually monitor regional news coverage of project and respond to reports with additional information and clarification
 - Monitor news coverage of similar projects in other parts of the state, or the nation and link the project by inference to successes elsewhere
 - Select materials should be prepared in Spanish and other appropriate languages to facilitate coverage by all media outlets

Press releases and outreach can be triggered by a predetermined set of milestones. As each milestone is achieved (contract award, design complete, initial roll-out, initial operations), a press release can be issued automatically. A complementary strategy is to develop press releases at key points in the process, following particularly insightful public meetings or after successful events. Exhibit V-1 presents some of the primary components of press outreach.

Paid advertising is a way to reach large segments of the population. The implementing entity will need to determine if this approach is feasible given the high costs associated with such an effort. Elements of such an advertising campaign can include drive time, outdoor, 30-second radio and TV spots and newspaper ads.

Exhibit V-1 Outreach Components

| COMPONENT | DESCRIPTION |
|---|--|
| Feature stories and columns | Articles placed in local newspapers, civic newsletters (church, business, day care and senior centers, etc.) and publications. Include information on renewable technology, the benefits to customers and a number to call for more information. |
| Script for guest appearances on local cable and radio morning talk shows. | Time appearances prior to major project implementation milestones. Radio timed to morning commutes. Position San Francisco as the state leader in clean technology. |
| Smart News | A publication designed to keep internal staff, media, and interested parties aware of program implementation progress. |
| Bill Inserts | Announcements should be timed to launch. Have full publications available to describe program in further detail. |
| Radio, TV Promotion | Develop stories, near key milestones and launch time, with one or two stations. |
| Press Kit | Include fact sheets or newsletter, list of Board members and political leaders, overview of program and technology. Include copies of logos and tag-line for use in publications. |
| Press Release | Article designed to focus on regional benefits, as well as cutting-edge technology. Timed to coincide with project milestones. Press invited to attend ribbon-cuttings. |
| Education Materials | Fact sheets, bulletins, newsletters, web sites and presentation materials. These can be tailored for outreach audiences as well as employees of targeted stakeholders. |

4.3 Design

The first phase of the implementation process for the renewable energy technology infrastructure is design development and review. The implementing entity will be responsible for review of design submittals from the ESP in keeping with the approved contract schedule. The design review determines whether the ESP's submittals are in compliance with the technical scope and contract, and all applicable federal, state, and local laws, statutes, ordinances, regulations, codes, orders, and decrees. Throughout the process, the implementing entity will need to evaluate any value engineering change proposals, and proposed modifications to existing installations or systems.

4.4 Testing, Inspection and Quality Assurance

The implementing entity will be responsible for controlling, monitoring, and enforcing the ESP's compliance to all technical and operational requirements, terms, and conditions, as specified in the ESP contract as the program moves from design to testing and ultimately to installation. The implementing entity will also monitor the ESP's performance to quality assurance (QA) standards, compliance with their own quality assurance program, and provide oversight during all phases of testing, manufacturing, and installation. The ESP shall test all components, sub-systems, and systems processes constituting the system individually and together. The major inspections and tests to be conducted include:

- Unit Inspection and Testing
- Production Inspection and Testing
- Interface and Integration Inspection and Testing
- Installation and Acceptance Inspection and Testing

4.5 Installation

The implementing entity will work with the ESP site owners to develop a complete understanding of the specific installation requirements at each site. The implementing entity will ensure that ESP plans for site preparation work meet the requirements of the ESP contract. The implementing entity will oversee site preparation work and the installations themselves. Real property and siting issues are further addressed in Section 4.2.

4.6 Training

To the degree that the ESP has operations and maintenance responsibilities, they will be expected to have competent, trained staff performing the work. The implementing entity should review the ESP's training program (including manuals and actual classes) to help ensure that the program supports the desired service levels.

4.7 Changes and Claims

A project of this scale and complexity will undoubtedly have changes and challenges as it unfolds. The implementing entity's role is to sort legitimate changes from non-legitimate ones and implement claims avoidance measures in order to mitigate the size and number of potential claims. In this role, they will evaluate the risks and identify alternatives for mitigating potential claims.

4.8 Intergovernmental Coordination

Throughout implementation, the implementing entity will need to coordinate the inputs and participation of many governmental and regulatory bodies. This function cuts across implementation phases and discipline areas. The most effective and useful ways of coordination would have been identified and planned for during the Program Development Phase and through the Communications Plan. Identifying key stakeholders and looking at the effectiveness of existing channels for communication amongst these stakeholders will play a big part in ensuring and improving upon any intergovernmental coordination.

Development of performance measures will be critical for understanding how well the program is being implemented, whether there needs to be changes to how feedback is collected, or how the program needs to become more convenient or provide greater customer value.

4.9 Performance Measure and Feedback from Stakeholders and Customers

The implementing entity will need to track and record the feedback from both stakeholders and customers. The ability to know what to track and how it will help with process improvement is important. These measures would have been developed during the Program Development phase as a result of clearly defined goals for the program and for communications efforts. Developing measures also must factor in how one part of the project touches another part so that measures roll up towards the high-level goals defined by the program. Identifying who will be responsible for tracking measures across the project and how that information needs to be reported will be critical for measuring project progress.

5.0 Operations And Maintenance

The final piece of a comprehensive implementation plan addresses the eventual shift from building a program to operating a service. By design, the implementing entity has a finite existence and must hand over long-term operating responsibility to another entity. The transition between implementing entity and operating entity will not be a single event. Rather, operating entity will phase in while implementing entity continues their work to build the program. Eventually, when the build phases are substantially complete, the implementing entity can phase out and the operating entity can fully take over.

5.1 Operating Entity Responsibilities

The logical long-term operating entity is the SFPUC. In the role as operating entity, they would have responsibility for

- ESP contract management
- Financial management
- Ongoing ESP performance monitoring
 - Oversight of ESP maintenance
 - Oversight of ESP customer services
- Ratesetting processes
- Outreach and education
- Planning
- Follow-on contracting

5.2 Termination

While the whole purpose of a comprehensive implementation plan is to ensure a successful program, to protect ratepayers the City must always have the option of terminating an ESP contract and/or terminating the entire CCA program. In such an instance, the City must continue to provide power to customers through another means. In a termination scenario, continued service could be provided through an alternate ESP, the City itself (as a municipal utility), or by reverting back to the investor owned utility.

Contractual and technical terms for termination will be spelled out in detail in the ESP RFP and ultimately in the contract with the selected ESP. Termination clauses must be designed with care, as they can translate into potential risk for ESP's and therefore may manifest themselves in higher program costs.

The costs associated with termination and continued service must not result in costs above the "meet or beat" rates under the ESP rate proposal. Any costs falling outside those limits must be borne by the termination itself, for example, through the performance bond of the ESP, legal proceedings for non-performance, or financed through savings expected from the change, for example, by changing ESPs.

VI. CUSTOMER CHARACTERISTICS AND CONTEXT

Incorporate SFPUC/SFE Chapter 2, "Customer Characteristics and Context") in its entirety by adding a new chapter (VI) to the final Draft Implementation Plan. Edit new

Chapter VI for terminology consistency and cross referencing. See Attachment A of this Amendment for the current version of SFPUC/SFE Chapter 2.

APPENDICES

A. Statutory Compliance Matrix

Add relevant CPUC related dates to the Implementation Plan Schedule.

| ITEM | REQUIREMENT | STATUTE REFERENCE | IMP. PLAN SECTION |
|------|---|------------------------------|---------------------------|
| 1 | The process and consequences of aggregation | 366.2(c)(3) | II, II-4.0, II-5.0, IV, V |
| 2 | An <i>{The appropriate scope and}</i> organizational structure of the program, its operations, and its funding. | 366.2(c)(3)(A), SF Sec.3.A.1 | II, IV, V |
| 3 | <i>City ratesetting mechanisms</i> and other costs to participants | 366.2(c)(3)(B), SF Sec.3.A.2 | II, IV, V |
| 4 | The benefits of the program to San Francisco customers | SF Sec.3.A.3 | II, IV, V, V-4.2 |
| 5 | How the program can meet or exceed the renewable portfolio standard required of PG&E under state law | SF Sec.3.A.4 | II, IV, V |
| 6 | How the program can meet or exceed consumer protection standards required of PG&E by the CPUC including: {8 and 10 below} | SF Sec.3.A.5 | II, IV, V, V-2.2 |
| 7 | Provisions for disclosure and due process in setting rates and allocating costs among participants | 366.2(c)(3)(C), SF Sec.3.A.5 | V, V-2.4, V-4.2 |
| 8 | The methods for entering and terminating agreements with other entities | 366.2(c)(3)(D) | II, IV, V |
| 9 | The rights and responsibilities of program participants, including, but not limited to, consumer protection procedures ¹ , credit issues, and shutoff procedures | 366.2(c)(3)(E), SF Sec.3.A.5 | IV, IV-4.0, V, V-4.2 |
| 10 | Termination of the program | 366.2(c)(3)(F), SF Sec.3.A.7 | V, V-2.5, V-4.2 |
| 11 | A description of the <i>{How the program will provide information about any}</i> third parties that will be supplying electricity <i>or providing other services</i> under the program, including, but not limited to, information about financial, technical, and operational capabilities | 366.2(c)(3)(G), SF Sec.3.A.6 | II, IV, V, V-4.2 |
| 12 | What functions of the program should be performed by entities other than the City, including an Electric Service Provider (ESP) or its subcontractors | SF Sec.3.A.8 | II, IV, V, V-2.4, V-2.5 |
| 13 | Appropriate contract and bid requirements, including {items 15 through xx}: | SF Sec.3.A.9 | II, IV, V |

¹ “Consumer protection procedures” not repeated in the SF Ordinance, covered in Items 6 and 7

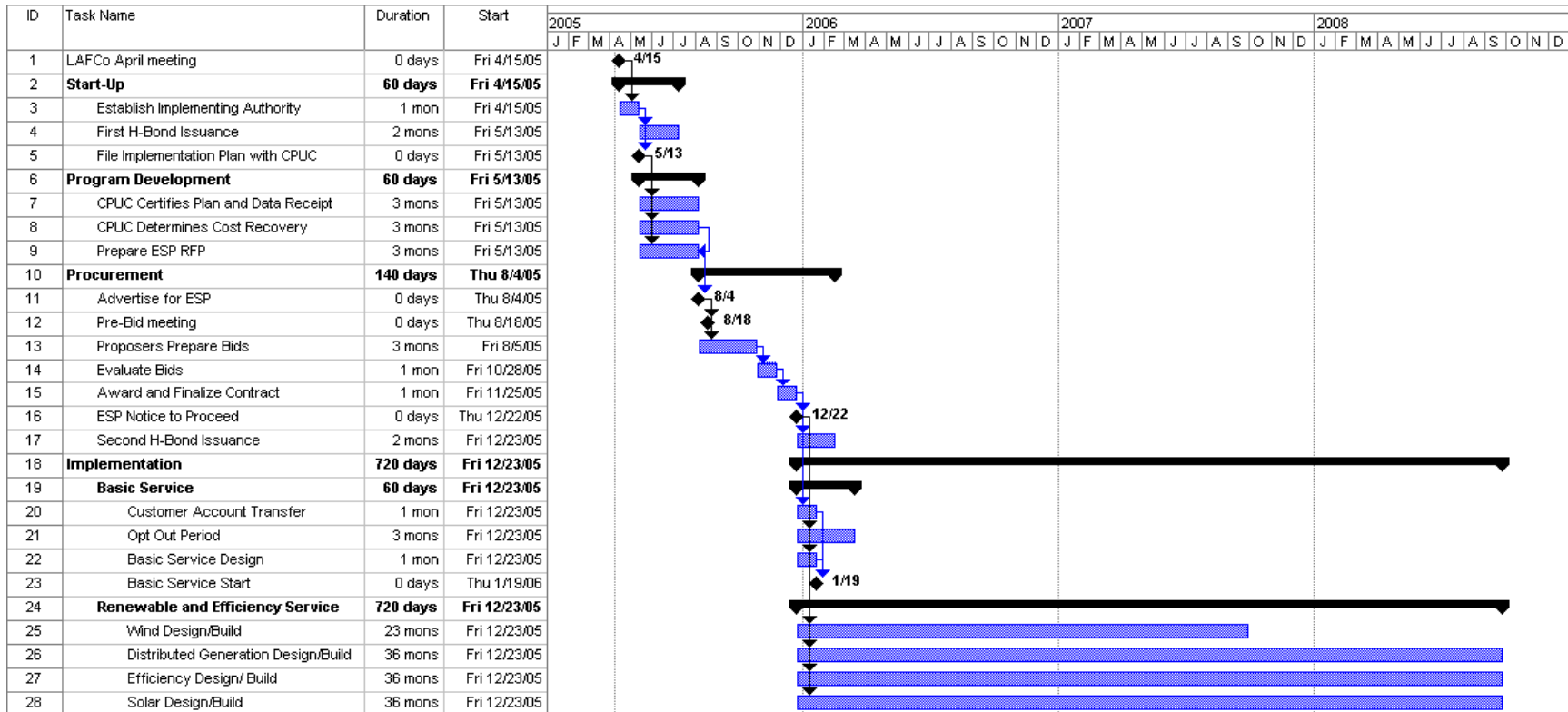
** Italics represent wording specific to the SF Ordinance when similar requirements appear in both the ordinance and AB117(requirements now reflected in the Public Utilities Code).*

| ITEM | REQUIREMENT | STATUTE REFERENCE | IMP. PLAN SECTION |
|--|---|-------------------|--------------------------------------|
| 14 | Desired portfolio of resources that exceeds goals for energy efficiency, renewable energy, peak shaving and load management provided for in the City's adopted Electricity Resource Plan | SF Sec.3.A.9.I | II, IV, V |
| 15 | Recommended contract periods designed to optimize meeting Electricity Resource Plan goals and to provide reasonable repayment schedule for debt | SF Sec.3.A.9.II | II, II-4.3, IV, V |
| 16 | A requirement that bids include proposals for rate design, with all costs and profits associated with providing the various components of its proposed service package, including the costs of designing, building, operating and maintaining all renewable energy, conservation and energy efficiency installations, as well as, any capital, insurance and other costs associated with fulfilling the commitments made in its bid | SF Sec.3.A.9.III | II, II-4.3, IV, V, V-2, V-2.6, V-3.0 |
| 17 | Recommended bid evaluation mechanisms that will encourage respondents to compete based on the environmental and local economic benefits of their proposed portfolio of energy resources | SF Sec.3.A.9.IV | V |
| 18 | Recommended contract provisions that will provide financial incentives to the City's Electric Service Provider, if one is selected, to accelerate deployment of and/or expand the energy efficiency and renewable energy components of its proposed energy portfolio | SF Sec.3.A.9.V | II, IV, V |
| OTHER ITEMS REQUIRED WITH IMPLEMENTATION PLAN | | | |
| 19 | Statement of intent (A) Universal access (B) Reliability (C) Equitable treatment of all classes of customers (D) Any requirements established by state law or by the commission concerning aggregated service | 366.2(c)(4) | II, IV, V |
| 20 | A report on any CPUC or other developments that might impact the City's effort to proceed with implementation of a Community Choice Aggregation. | SF Sec.3.A | II, IV, V |

ATTACHMENT A

**SFPUC/SFE COMMUNITY CHOICE AGGREGATION
DRAFT IMPLEMENTATION PLAN
CHAPTER 2: CUSTOMER CHARACTERISTICS AND CONTEXT**

B. Program Schedule



C. Appendix C – Not Used

D. PG&E Current Rate Schedules

E. Electric Service Provider List

**Potential Electrical Service Providers (ESP)
Currently Registered in California**

| COMPANY | SUMMARY | TECHNICAL AND OPERATIONAL CAPABILITIES | FINANCIAL HIGHLIGHTS |
|---|--|--|--|
| <p><u>3 Phases Electrical Consulting</u> 2100 SEPULVEDA BLVD, SUITE 15 MANHATTAN BEACH, CA 90266 ESP # 1350 Phone: (310) 798-5275 Fax: (310) 545-4218 E-mail: mmazur@3phases.com</p> <p>Officer: Michail Mazur, Founder and Chief Technical Officer</p> | <p>3 Phases Energy Services was founded in 1994. 3 Phases mission is to expand the frontiers of the renewable energy marketplace in the design of a sustainable energy future. It is a private company with approximately 8 employees. 3 Phases offers renewable energy nationwide, serving residential, nonprofit, corporate, and utility customers in every major city in the United States via a suite of renewable power generation facilities across the United States.^{2,4}</p> | <p>In 2000, 3 Phases began offering direct access services to area residents and businesses under California's deregulation. 3 Phases expanded into wholesale and retail tradable renewable certificates (Green Certificates) and added a program to offer green pricing for investor and municipal-owned utilities. 3 Phases also has an onsite power division, specializing in solar photovoltaic and energy efficiency equipment. 3 Phases supports over forty landfill gas, biomass, geothermal, and solar generation facilities across the United States.²</p> | <p>3 Phases Energy Services has annual sales of approximately \$5 million.⁴</p> |
| <p><u>American Utility Network (A.U.N.)</u> 10705 DEER CANYON DRIVE ALTA LOMA, CA 91737 ESP # 1158 Phone: (909) 484-1858</p> <p>Officer: Frank Annu N. Ziato, President</p> | <p>American Utility Network is a private company.</p> | <p>Not available</p> | <p>Not available</p> |
| <p><u>AOL Utility Corp.</u> 12752 BARRETT LANE SANTA ANA, CA 92705 ESP # 1355 Phone: (714) 669-2743 Fax: (775) 406-3253 E-mail: lalehs101@hotmail.com</p> <p>Officer: Paul Oshideri, President</p> | <p>AOL Utility Corp. is a private company with approximately 7 employees.⁴</p> | <p>Not available</p> | <p>AOL Utility has annual sales of approximately \$500 thousand.⁴</p> |

| COMPANY | SUMMARY | TECHNICAL AND OPERATIONAL CAPABILITIES | FINANCIAL HIGHLIGHTS |
|--|---|---|--|
| <p><u>APS Energy Services Company, Inc.</u> 400 E. VAN BUREN STREET SUITE 750 PHOENIX, AZ 85004 ESP # 1361 Phone: (602) 744-5364 Fax: (602) 744-5236 E-mail: sjenine.schenk@apses.com</p> <p>Officers: Vicki Sandler, President</p> | <p>APS Energy Services is the full-service energy services provider and competitive electricity subsidiary of Pinnacle West Capital Corporation, publicly held Arizona-based company. APS employs approximately 55 staff.²</p> | <p>APS Energy Services develops customized solutions to meet energy-related issues such as: energy master planning, energy supply consultation, provision of supply and simple billing, energy procurement, energy use consultation and facility audits, end-use operational solutions, state-of-the-art energy information tools, turn-key management and installation, and customized financing.²</p> | <p>APS has annual revenue of \$226 million. Parent Company Pinnacle West Capital Corp has consolidated assets of approximately \$9.5 billion and consolidated revenues of \$2.8 billion.^{2,4}</p> |
| <p><u>BP Energy Company</u> 501 WESTLAKE PARK BLVD. HOUSTON, TX 77079 ESP # 1366 Phone: (281) 366-4627 Fax: (281) 366-2200 E-mail: prescorw@bp.com</p> <p>Officers: Tim Bullock, President Jim Dewar, Chief Financial Officer</p> | <p>BP Energy Company is a subsidiary of BP PLC. It has approximately 150 employees. BP PLC has four main businesses: Exploration and Production; Gas, Power and Renewables; Refining and Marketing, and Petrochemicals. The Gas, Power and Renewables group activities include marketing and trading of natural gas, natural gas liquid, new market development, liquefied natural gas, solar and renewables.^{1,4}</p> | <p>BP's marketing and trading activities are focused on the deregulated natural gas and power markets of North America, the United Kingdom and certain parts of continental Europe. The Company's solar and renewables activities include the development, production and marketing of solar panels and the development of wind farms. BP Solar is one of the world's leading producers of photovoltaic solar cells with a 17% market share. In 2002 BP announced the start-up of a 22.5 megawatt wind farm in the Netherlands and the first commercial sale of green electricity into the Dutch national power grid. Other activities include gas-fired power generation projects.^{1,2}</p> | <p>BP Energy has annual revenue of \$226 million. For the fiscal year ended 12/31/04, parent company BP PLC revenues rose 23% to \$285.06 billion. Net income rose 43% to \$16.97 billion.^{1,4}</p> |
| <p><u>Calpine PowerAmerica-CA, LLC</u> 4160 DUBLIN BLVD. DUBLIN, CA 94568 ESP #1362 Phone: (925) 479-6600 Fax: (925) 479-7304 E-mail: curth@calpine.com</p> <p>Officers: Curt Hildebrand</p> | <p>Calpine PowerAmerica is the retail energy service provider subsidiary of Calpine Corporation. Calpine Corp. is a North American power company engaged in the development, construction, ownership and operation of power generation facilities and the sale of electricity predominantly in the United States, as well as in Canada</p> | <p>As of December 31, 2003, Calpine Corp. owned interests in 87 power plants having a net capacity of 22,206 megawatts (MW). Of these projects, 68 were gas-fired power plants with a net capacity of 21,356 megawatts, and 19 were geothermal power generation facilities with a net capacity of 850 megawatts. Each of the power</p> | <p>Calpine PowerAmerica has annual revenue of approximately \$110 thousand. For the fiscal year ended 12/31/04, parent company Calpine Corp. revenues rose 4% to \$9.23 billion. Net loss from continuing operations and</p> |

| COMPANY | SUMMARY | TECHNICAL AND OPERATIONAL CAPABILITIES | FINANCIAL HIGHLIGHTS |
|---|--|---|--|
| <p>Vice President of Marketing and Sales</p> | <p>and the United Kingdom. The Company focuses on two types of power generation technologies, natural gas-fired combustion turbine and geothermal.¹</p> | <p>generation facilities in operation produces electricity for sale to a utility, other third-party end user or to an intermediary such as a trading company. The Company holds interests in geothermal leaseholds in Lake and Sonoma Counties in northern California (The Geysers). The Geysers produce steam that is supplied to geothermal power generation facilities owned by the Company for use in producing electricity.¹</p> | <p>before acctng. change totalled \$440.8 million vs. income of \$86.1 million.^{1,4}</p> |
| <p><u>City of Corona Department of Water & Power</u> 730 CORPORATION YARD WAY CORONA, CA 92880 ESP # 1367 Phone: (951) 739-4967 Fax: (951) 735-3786 E-mail: georgeh.@ci.corona.ca.us</p> | <p>Not available</p> | <p>Not available</p> | <p>Not available</p> |
| <p><u>Constellation NewEnergy, Inc.</u> 350 SOUTH GRAND AVENUE SUITE 2950 LOS ANGELES, CA 90071 ESP # 1359 Phone: (888) 526-0486 Fax: (213) 576-6070 E-mail: carol.schoenbachler@constellation.com</p> <p>Officers: Clem Palevich, President and Chief Executive Officer Kathleen Hyle, Chief Financial Officer</p> | <p>Constellation NewEnergy is the retail energy service provider subsidiary of Constellation Energy Group Inc. Constellation NewEnergy employs approximately 280 staff. Constellation Energy Group Inc. is a North American company, which includes a merchant energy business and the Baltimore Gas and Electric Company (BGE), a regulated electric and gas public utility in central Maryland. It has four operating segments: merchant energy, regulated electric, regulated gas and other nonregulated. Its merchant energy business is a provider of energy solutions.^{1,4}</p> | <p>Constellation's merchant energy business serves the energy and capacity requirements (load-serving) of, and provides other energy products and risk-management services for various customers, such as utilities, municipalities, cooperatives, retail aggregators, and commercial and industrial customers. The Company's merchant energy business includes a generation operation that owns, operates and maintains fossil, nuclear and hydroelectric generating facilities, and interests in qualifying facilities, fuel processing facilities and power projects in the United States. Constellation NewEnergy, the Company's electric and gas retail operation, provides electricity, natural gas, transportation and other</p> | <p>Constellation NewEnergy annual Sales are approximately \$77.2 million. For the fiscal year ended 12/31/04, parent company Constellation Energy Group revenues rose 30% to \$12.55 billion. Net income from continuing operations and before acct. chg. rose 24% to \$588.8 million.^{1,4}</p> |

| COMPANY | SUMMARY | TECHNICAL AND OPERATIONAL CAPABILITIES | FINANCIAL HIGHLIGHTS |
|--|--|--|--|
| <p>Coral Power, L.L.C. 4445 EASTGATE MALL, SUITE 100 SAN DIEGO, CA 92121 ESP # 1360 Phone: (858) 320-1500 Fax: (858) 320-1550 E-mail: hharris@coral-energy.com</p> <p>Officers (Coral Energy Holding): Deborah Wernet, President Susan Hodge, Chief Financial Officer</p> | <p>The parent company to Coral Power, LLC is Coral Energy Holding, L.P. Coral Energy is an affiliate of the Royal Dutch / Shell group of companies. Coral Energy and its subsidiaries are an integral part of the Shell Trading network in North America, providing electricity, natural gas and risk management services. Coral Power Western Region operations and trading are headquartered in San Diego, California, with natural gas and electric marketing offices located in Oakland, California and Portland, Oregon. Shell Trading is a global business network integrating the worldwide energy trading activities of Shell. Operating as part of the Shell Trading network, Coral Energy's subsidiaries are among the top ten energy marketers in North America and the sole marketers of Shell's 7.5 trillion cubic feet of gas reserves in the US and Canada.²</p> | <p>energy services to commercial and industrial customers.¹</p> <p>Through its relationship with Coral Energy and Shell Trading, Coral Power's capabilities include load forecasting, schedule coordination, wind power forecasting and scheduling, generation optimization, transmission and transportation management, risk management, long and short-term transaction structuring. The West Region maintains a 24-hour per day power trading and dispatch center in its San Diego office. Alliance relationships are in place with municipalities, as well as independent power producers. The West Region is currently moving over 6,500 MW/hrs of wholesale electric energy and 3.0 Bcf/day of natural gas in the WECC.²</p> | <p>Coral Power LLC's annual Sales are approximately \$4.3 million.⁴</p> |
| <p>electricAmerica 600 ANTON BOULEVARD SUITE 2000 COSTA MESA, CA 92626 ESP # 1092 Phone: (714) 259-2508 Fax: (714) 259-2516 E-mail: igoodman@electric.com</p> <p>Officers (Commerce Energy Group): Peter Weigand, President Richard L. Boughrum, CFO and Senior Vice President</p> | <p>electricAmerica and Commonwealth Energy have combined with ACN Energy to become Commerce Energy. Commerce Energy started as a provider of residential energy service to customers in California, and now serves residential customers in six states. Commerce Energy is a subsidiary of Commerce Energy Group, a publicly held, diversified energy services company. Commerce Energy Group provides retail electric power to its residential, commercial, industrial and institutional customers and</p> | <p>Commerce Energy predecessor company Commonwealth Energy Corporation began delivering electricity to California consumers in March of 1998 and grew to become the largest ESP in California, capturing over 60% of all switched accounts statewide.²</p> | <p>For the six months ended 01/31/05, Commerce Energy Group revenues rose 13% to \$119.5 million. Net income totaled \$252 thousand vs. a loss of \$8.8 million.¹</p> |

| COMPANY | SUMMARY | TECHNICAL AND OPERATIONAL CAPABILITIES | FINANCIAL HIGHLIGHTS |
|---|---|--|--|
| | <p>provides consulting and technology services to energy-related businesses and provides energy transaction data management services. Commerce Energy Group is a holding company that operates through its wholly owned operating subsidiaries.^{1,2}</p> | | |
| <p><u>Energy America, LLC</u> 263 TRESSER BLVD., ONE STAMFORD PLAZA 8TH FLOOR STAMFORD, CT 06901 ESP # 1341 Phone: (416) 590-3290 Fax: (416) 590-3632 E-mail: adrian.pye@na.centrica.com</p> <p>Officers: Lois Hedg-Peth, Chief Executive Officer Demi Tsioros, Vice President Finance</p> | <p>Energy America, along with Direct Energy, are subsidiaries of Centrica North America offering deregulated retail energy services in the United States.²</p> | <p>Centrica North America provides gas, electricity and related services to more than 1.5 million customers in Texas, Michigan, Ohio, Pennsylvania, Rhode Island, Connecticut and Massachusetts through its Direct Energy brand, and CPL Retail Energy and WTU Retail Energy brands in South and West Texas.²</p> | <p>Energy America has annual sales of approximately \$9.2 million.⁴</p> |
| <p><u>Modesto Irrigation Dist. MID, MID Water & Power</u> 1231 ELEVENTH STREET P.O. BOX 4060-95352 MODESTO, CA 95354 ESP # 1151 Phone: (209) 526-7560 Fax: (209) 526-7359 E-mail: ronm@mid.org</p> <p>Officers: Allen Short, General Manager</p> | <p>Modesto Irrigation District (MID) is a not-for-profit, state-owned organization formed by the government of Stanislaus County in 1887 to provide irrigation services in the area.⁴</p> | <p>In addition to water related services, the utility generates, transmits, and distributes electricity to more than 100,000 residential and business customers; markets wholesale power.⁴</p> | <p>MID has annual sales of approximately \$216.6 million.⁴</p> |
| <p><u>New West Energy</u> PO BOX 61868 MAILING STATION ISB 665 PHOENIX, AZ 85082-1868 ESP # 1063 Phone: (888) 639-9674 Fax: (602) 236-5443 E-mail: tmrabcico@sprnet.com</p> | <p>According to their website, New West Energy is no longer offering service to customers in California.</p> | <p>Not available</p> | <p>Not available</p> |

| COMPANY | SUMMARY | TECHNICAL AND OPERATIONAL CAPABILITIES | FINANCIAL HIGHLIGHTS |
|---|--|---|--|
| <p>Officers: Robert Nichols, Managing Director</p> <p>Pilot Power Group, Inc. 9320 CHESAPEAKE DRIVE, SUITE 112 SAN DIEGO, CA 92123 ESP # 1365 Phone: (858) 627-9577 Fax: (858) 627-9581 E-mail: tdarton@pilotpowergroup.com</p> <p>Officers: John Mellor, President</p> | <p>Pilot Power is a private company with approximately 7 employees.⁴</p> | <p>Not available</p> | <p>Pilot Power has annual sales of approximately \$760 thousand.⁴</p> |
| <p>Quiet Energy 3311 VAN ALLEN PL. TOPANGA, CA 90290 ESP # 1368 Phone: (310) 656-9800 X211 Fax: (310) 656-9860 E-mail: mike@quietllc.com</p> <p>Officers: Mike Kasaba, President</p> | <p>Quiet Energy is a private company with approximately 3 employees.⁴</p> | <p>Quiet Energy is an Energy Service Provider serving large commercial and industrial users of electricity. They advocate the use of renewable energy, such as solar, wind, hydrogen, and biomass.²</p> | <p>Quiet Energy has annual sales of approximately \$1 million⁴</p> |
| <p>Sempra Energy Solutions 101 ASH STREET, HQ09 SAN DIEGO, CA 92101-3017 ESP # 1364 Phone: (877) 273-6772 Fax: (619) 696-3103 E-mail: email@semprasolutions.com</p> <p>Officers: Keith Erbin, President</p> | <p>Sempra Energy is an energy services holding company operating through subsidiaries to develop energy infrastructure, operate utilities and provide related products and services to more than 29 million consumers in the United States, Europe, Canada, Mexico, South America and Asia. Regulated businesses operate under Sempra Utilities (Southern California Gas Company (SoCalGas) and San Diego Gas & Electric (SDG&E)). Sempra Global is the umbrella company for Sempra Commodities, Sempra Generation, Sempra Pipelines & Storage, and Sempra LNG and several smaller business units. Sempra Energy Solutions, the retail energy marketing and services unit, was</p> | <p>Sempra Generation develops and operates merchant power plants and energy infrastructure for the competitive market. Its portfolio of generation assets total about 3,650 megawatts from three wholly owned facilities (two natural gas-fired and one coal-fired) and 50-percent ownership in seven facilities (six natural gas-fired and one coal-fired). The electricity generated by these plants is sold to the wholesale market and retail electricity providers, such as utilities, marketers and large energy users. Sempra Commodities provides worldwide marketing and risk-management services to wholesale customers for natural gas, power, petroleum products and base metals.²</p> | <p>For the fiscal year ended 12/31/04, Sempra Energy revenues increased 19% to \$9.41 billion. Net income from continuing operations before accounting change rose 32% to \$920 million.¹</p> |

| COMPANY | SUMMARY | TECHNICAL AND OPERATIONAL CAPABILITIES | FINANCIAL HIGHLIGHTS |
|--|---|---|---|
| | restructured in early 2005 amidst a larger company reorganization and its operations now reside under the Sempra Generation and Sempra Commodities units. ^{1,4} | | |
| <p>Strategic Energy, L.L.C. 7220 AVENIDA ENCINAS, SUITE 120 CARLSBAD, CA 92009 ESP # 1351 Phone: (888) 925-9115 Fax: (412) 258-4866 E-mail: customerrelations@sel.com</p> <p>Officers: Shahid Malik, President and CEO Andrew J. Washburn, CFO</p> | <p>Strategic Energy is a competitive supplier of retail electricity operating in ten states with deregulated energy markets, including California, Connecticut, Maryland, Massachusetts, Michigan, New Jersey, New York, Ohio, Pennsylvania and Texas. Strategic employs more than 275 full-time energy professionals. It is a subsidiary of Great Plains Energy, a publicly traded company. In addition to Strategic Energy, Great Plains operates a regulated utility, Kansas City Power & Light (KCP&L).²</p> | <p>Strategic Energy began serving retail electricity customers in 1997 as a participant in Pennsylvania's Pilot Program. They began serving Massachusetts, California and New York in 2000, Ohio in 2001, Texas in 2002, New Jersey and Michigan in 2003 and Connecticut and Maryland in 2004. Strategic now serves more than 7,000 commercial, institutional and industrial customers in states that have enacted retail choice.²</p> | <p>Strategic Energy's 2004 revenues totaled approximately \$1.4 billion²</p> |

¹ source: Reuters, Yahoo Finance

² source: Company Website

³ source: Company Fact Sheet

⁴ source: Hoover's Online

**Potential Electrical Service Providers (ESP)
Currently Serving Customers in Other CCA States
(Not Currently Registered in CA*)**

| COMPANY | SUMMARY | TECHNICAL AND OPERATIONAL CAPABILITIES | FINANCIAL HIGHLIGHTS |
|---|--|---|---|
| <p><u>FirstEnergy Solutions</u> 395 Ghent Road Akron, Ohio 44333 Phone: (800) 736-3402 Fax: (330) 384-3772</p> <p>Officers (FirstEnergy Corp): Anthony Alexander President, Chief Executive Officer, Director Richard Marsh Chief Financial Officer, Senior Vice President</p> | <p>FirstEnergy Corp. (FirstEnergy) is a public utility holding company that provides regulated energy services. The Company has eight principal electric utility operating subsidiaries: Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Pennsylvania Power Company, American Transmission Systems, Inc., Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric Company. FirstEnergy's other principal subsidiaries are FirstEnergy Solutions Corp. (unregulated), FirstEnergy Facilities Services Group, LLC, MYR Group, Inc. and First Communications, LLC.¹</p> | <p>FirstEnergy Corp. operates 20 power plants with a total system capacity of more than 13,000 megawatts. Altogether, the Company produces nearly 70 million megawatt hours of electricity each year to meet its customers' needs. FirstEnergy Solutions, an unregulated subsidiary of FirstEnergy Corp., offers a wide range of energy and related products and services, including the generation and sale of electricity; exploration, production and sale of natural gas; mechanical and electrical contracting and construction; and energy management. FirstEnergy Solutions is a licensed electric supplier in Ohio, Pennsylvania, New Jersey, Delaware, Maryland, Michigan and Washington, D.C.²</p> | <p>For the fiscal year ended 12/31/04, First Energy Corp. revenues rose 7% to \$12.45 billion. Net income from continuing operations and before accounting change rose from \$424.2 million to \$873.8 million.¹</p> |

| COMPANY | SUMMARY | TECHNICAL AND OPERATIONAL CAPABILITIES | FINANCIAL HIGHLIGHTS |
|---|---|--|---|
| <p><u>Allegheny Power</u> 800 Cabin Hill Drive Greensburg, Pa. 15601-1689 Phone: (724) 837-3000 Fax: (301) 665-2736</p> <p>Officers (Allegheny Energy, Inc.): Paul Evanson Chairman, President, Chief Executive Officer Jeffrey Serkes Chief Financial Officer, Senior Vice President</p> | <p>Allegheny Energy, Inc. (AE) is a diversified utility holding company that operates in the core businesses of electricity generation, and transmission and distribution, primarily through direct and indirect subsidiaries. The Company is an integrated energy business that owns and operates electric generation facilities and delivers electric and natural gas services to customers in Pennsylvania, West Virginia, Maryland, Virginia and Ohio. Allegheny has two business segments: the Delivery and Services segment that includes Allegheny's electric and natural gas transmission and distribution (T&D) operations, and the Generation and Marketing segment, which includes Allegheny's power generation operations.¹</p> | <p>Allegheny Power is the energy delivery business of Allegheny Energy, delivering electricity and natural gas to about three and one-half million people in parts of Maryland, Ohio, Pennsylvania, Virginia, and West Virginia²</p> | <p>For the fiscal year ended 12/31/04, Allegheny Energy Inc. revenues rose 26% to \$2.76 billion. Net income from continuing operations before acct. change totaled \$129.7 million, vs. a loss of \$308.9 million.¹</p> |
| <p><u>American Electric Power</u> 1 Riverside Plaza Columbus, OH 43215-2373 Phone: (614) 716-1000 Fax: (614) 223-1823</p> <p>Officers: Michael Morris, Chairman, President, Chief Executive Officer Susan Tomasky Chief Financial Officer, Executive Vice President of AEP and of AEPSC</p> | <p>American Electric Power Company, Inc. (AEP) is a registered public utility holding company that owns, directly or indirectly, all of the outstanding common stock of its public utility subsidiaries and varying percentages of other subsidiaries. The public utility subsidiaries of AEP are American Electric Power Company, Inc., AEP Generating Company, AEP Texas Central Company, AEP Texas North Company, Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company. The service areas of AEP's public utility subsidiaries cover portions of the states of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia.¹</p> | <p>American Electric Power owns more than 36,000 megawatts of generating capacity in the United States and is the nation's largest electricity generator. AEP is also one of the largest electric utilities in the United States, with more than 5 million customers linked to AEP's 11-state electricity transmission and distribution grid. The company owns two wind generation facilities totaling 310 megawatts of generating capacity, and is involved with another company in a third project²</p> | <p>For the fiscal year ended 12/31/04, revenues decreased 4% to \$14.06 billion. Net income from continuing operations and before extraordinary items and acct. change totaled \$1.13 billion, up from \$522 million.¹</p> |

| COMPANY | SUMMARY | TECHNICAL AND OPERATIONAL CAPABILITIES | FINANCIAL HIGHLIGHTS |
|--|---|--|---|
| <p>Cinergy Corp 1139 East Fourth Street Cincinnati, OH 45202 Phone: (513) 421-9500 Fax: (513) 651-9196</p> <p>Officers: James Rogers Chairman, Pres, Chief Executive Officer James Turner Chief Financial Officer, Executive Vice President</p> | <p>Cinergy Corp. is a utility holding company that owns all outstanding common stock of The Cincinnati Gas & Electric Company (CG&E) and PSI Energy, Inc. (PSI). The Company's other subsidiaries are Cinergy Services, Inc. (Services), Cinergy Investments, Inc. (Investments) and Cinergy Wholesale Energy, Inc. (Wholesale Energy). The Company conducts operations through its subsidiaries and manages its businesses through its three segments: Commercial Business Unit; Regulated Businesses Business Unit (Regulated Businesses), and Power Technology and Infrastructure Services Business Unit (Power Technology).¹</p> | <p>Cinergy commercial businesses manage, operate and/or maintain our generation, and the marketing and trading of energy commodities, primarily natural gas and electricity. The marketing and trading of energy commodities includes energy risk management activities and customized energy solutions. Cinergy commercial businesses operate 13,331 megawatts of generating capacity, own and/or operate 19 cogeneration projects with over 1,200 megawatts of generating capacity, marketed and traded 147.5 million megawatt-hours of over-the-counter contracts for the purchase and sale of electricity in 2003. Electricity generation including operation of coal, gas, cogeneration and renewable power plants.³</p> | <p>For the fiscal year ended 12/31/04, Cinergy Corp. revenues rose 6% to \$4.69 billion. Net income from continuing operations and before accounting change fell 8% to \$400.9 million.¹</p> |

| COMPANY | SUMMARY | TECHNICAL AND OPERATIONAL CAPABILITIES | FINANCIAL HIGHLIGHTS |
|--|--|--|---|
| <p>DPL Inc 1065 Woodman Drive Dayton, OH 45432 Phone: (513) 421-9500 Fax: (513) 651-9196</p> <p>Officers: James Mahoney Pres, Chief Executive Officer, Director John Gillen Senior Vice President and Chief Financial Officer DPL Inc. and DP&L</p> | <p>DPL Inc. (DPL) is a diversified regional energy company whose primary business is comprised of the activities of its subsidiary, The Dayton Power and Light Company (DP&L). DP&L is a public utility engaged in the sale, transmission and distribution of electricity to residential, commercial, industrial and governmental customers in a 6,000-square-mile area in West Central Ohio. Electricity for DP&L's 24-county service area is primarily generated at eight coal-fired power plants and is distributed to more than 500,000 retail customers. DP&L also purchases retail peak load requirements from DPL Energy LLC (DPLE), another subsidiary of the Company. Principal industries served include automotive, food processing, paper, plastic manufacturing and defense. DP&L sells any excess energy and capacity into the wholesale market.¹</p> | <p>DPL Energy is a diversified regional energy business, operating both coal fired generation capacity and natural gas fired peaking units. Capacity not sold to DP&L is marketed on a wholesale basis throughout the eastern United States.²</p> | <p>For the fiscal year ended 12/31/04, DPL Inc. revenues rose less than 1% to \$1.2 billion. Net income before acct. change rose 65% to \$217.3M.¹</p> |

* These organizations are potential new entrants to the California market either by registering as ESPs or as teaming partners to registered ESPs

¹ source: Reuters, Yahoo Finance

² source: Company Website

³ source: Company Fact Sheet

ATTACHMENT A

**SFPUC/SFE COMMUNITY CHOICE AGGREGATION
DRAFT IMPLEMENTATION PLAN
CHAPTER 2: CUSTOMER CHARACTERISTICS AND CONTEXT**

ATTACHMENT B
INTERIM CCA TARIFFS (REDLINE)
SUBMITTED BY PG&E TO CPUC
FEBRUARY 22, 2005

ATTACHMENT C

**CCA TASK FORCE RESOLUTION
SAN FRANCISCO BOARD OF SUPERVISORS RESOLUTION 757-04 "CREATING A COMMUNITY CHOICE
AGGREGATION CITIZENS ADVISORY TASK FORCE"**