Local Build-out of Energy Resources of the Community Choice Aggregation Program

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Final Draft

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EXECUTIVE SUMMARY

As successfully demonstrated by Marin Energy Authority and Sonoma Clean Power, Community Choice Aggregation (CCA) can be an effective method of increasing control of energy choices as well as increasing the utilization of clean renewable energy within a community. To increase San Francisco's use of renewable energy, CleanPowerSF (CPSF) needs a plan to acquire renewable energy that is manageable, affordable, available and achievable. Accordingly, this Local Build-Out Plan has been developed through the review and evaluation of the prior foundational work performed by and for CPSF. This Build-Out Plan presents recommendations that detail the next steps necessary for planning the build out of CPSF's CCA program.

In summary, this plan has made the following conclusions:

Task 1: Utilizing SFPUC for CPSF Power Procurement

SFPUC Power Procurement Evaluation

1) There is no need to pursue either resurrection of the Shell Energy North America (SENA) contract or any contract from the market with similar provisions. Instead, CPSF should go back to market – through the San Francisco Public Utilities Commission (SFPUC) Power Enterprise (PE) - to multiple suppliers to seek specific products and services (such as Power Purchase Agreements or CAISO Schedule Coordination) based on the portfolio strategy developed between SFPUC PE and CPSF. SENA may be one of the potential suppliers, but would be participating in any future solicitation (if invited by CPSF) as a new participant, completely divorced from the prior CPSF solicitation and contracting process.
2) In our opinion, at the highest level the CPSF program is a natural extension of the existing SFPUC PE function. Because the skills, expertise, processes and systems needed to manage the procurement and portfolio management services for CPSF are essentially the same as those already in use and being further developed and refined within SFPUC PE, potential benefits and economies of scale may result from PE's support of the CPSF.
3) The option of having the SFPUC PE provide procurement and portfolio management services directly in support of CPSF is consistent with and complimentary to PE's current and future functions and roles. Providing these services leverages existing expertise, skills, processes and systems. PE should be compensated for services provided using a payment methodology that best represents the underlying cost and the value of providing these critical services.
4) The size estimate for the initial phase of the CPSF program customer load of 20-30 MW was largely based on the initial power supply contracting strategy with Shell Energy North America (SENA). The reassessment or "resetting" of the CPSF program, which includes the

evaluation within this report for having SFPUC PE manage the CPSF supply portfolio, may introduce the opportunity to increase the initial program size. The constraints of doing so include using only existing capability and capacity of SFPUC PE staff and operations. Determination of the potential incremental increase in initial program size is beyond the scope of this report but is identified as a key action item for SFPUC PE and CPSF to examine when the program moves forward.

5) We believe there are benefits in economy, efficiency and scale by having SFPUC manage the CPSF supply portfolio. Economies of scale may result in fewer staff being required for later increments of increased load. Additional customers will likely present more diversity in load usage which would lower costs and reduce risk.
6) For the initial 20-30MW program, PE Staff comments indicated that they believe no new expertise would be required as the work anticipated is very consistent with the tasks that they are already performing. An incremental retail load of approximately 100 MW would likely require some incremental staff, particularly in the forecasting, scheduling and trading roles. An estimated 2-3 FTEs would be required to support an incremental load of 100 MW.
7) Utilizing SFPUC PE for forecasting and purchasing power for CPSF could utilize a transfer price, a Memorandum of Understanding (MOU) or some other mechanism to provide appropriate compensation for services rendered. CPSF would most certainly have to compensate a third party for these services and that compensation is most commonly embedded in the price charged. An assumption of “avoided cost” is a reasonable approximation for calculating the value provided. Use of a fixed allocation of PE staffing resource time is another viable value-determination approach, with an annual adjustment as the CPSF program grows. CPSF and SFPUC PE staff indicated that the fixed allocation approach is preferable for the initial CPSF program.
8) CPSF is planning to provide Customer Care Services through the use of a qualified service provider. This approach has proven cost effective and successful in other CCA implementations. While outsourcing Customer Care Services makes economic and efficient sense during the initial phase of CPSF, doing so does not preclude pulling some or all of these functions back into the SFPUC in the future. The existing SFPUC Customer Service group may be a viable option for CPSF Customer Care Services, as well as providing services to SFPUC’s growing retail customer base. SFPUC Customer Service currently has a Call Center, but would need to add the capacity to perform customer billing.
9) To successfully initiate the program CPSF has envisioned, the CCA will require the services of an experienced power market participant to manage the short and long term power

products portfolio and provide the daily operational functions necessary to schedule, balance and financially settle the power and ancillary services required to serve CPSF's customer load. These functions can be obtained either from one provider or from discrete providers of the specific services. For example, CPSF could procure CAISO Schedule Coordination services from a 3rd party (e.g. APX, TEA) and procure power products from the market through solicitations and setting up trading agreements with qualified market participants for transacting (purchase and sale) of energy products on daily and intra-day basis. While this approach is technically possible, it would be cost and time prohibited when compared to obtaining all the needed services from SFPUC PE.

10) CPSF will need to work periodically with PE to develop and agree to a working set of procurement scenarios that PE can execute against to build the CPSF supply portfolio including energy, capacity, ancillary services and resource adequacy
11) SFPUC PE and CPSF will need to develop a detailed MOU and/or transfer price agreement that documents, in a detailed manner (including settlement and dispute processes) how costs will transfer between the organizations and support cost/price transparency within CPSF.
12) SFPUC PE would work with CPSF staff to develop a mutually agreed-to procurement plan that best matched CPSF's forecasted load and incorporated market information that PE would normally have access to. For some types of energy products, PE would use a Request for Offers (RFO) process that is a common vehicle in the power markets for soliciting specific power products and services. PE would solicit RFOs from their existing qualified counter parties and the results obtained would be reviewed with CPSF to assure that market products and buy commitments were consistent with forecast CPSF revenue and rate levels.
13) In the near term, SFPUC PE would use their existing Scheduling Coordinator (SC) for servicing CPSF load, and would establish a separate CAISO Schedule Coordinator ID (SCID). A separate SCID would keep CPSF delivery and settlement data separate from existing and future SFPUC customers and would ensure that all related CAISO charges flow to CPSF for settlement and that charges would be captured in CPSF rates.
14) Because SFPUC PE is facing budget challenges which are requiring the use of limited reserve funds, CPSF funding sources could provide timely financial benefits to the PE department. The PE department is currently funding the GoSolarSF program which is providing benefits to San Francisco and is reducing the use of carbon-based fuels. However, funding of GoSolarSF is presenting budget issues for PE. CPSF could eventually fund a portion, if not all of the GoSolar program, by integrating GoSolarSF into the overall CPSF local resource build-out plan.

CPSF Strategy and Plans:

1) The development of local renewable energy has the potential to realize economic benefits for the City from the employment and expenditures for implementation activities and also from the shift of power spending from remote sources to sources within the City.
2) The current plan is for CPSF to offer a single option featuring 100% renewable energy for all customers. In addition to offering the 100% renewable energy option, CPSF should consider offering a Light Green plan that would balance a high percentage of renewable energy with a competitive rate. The proposed "Light Green" option would provide at least 50% renewable energy at a similar rate as PG&E's nominal rate. Currently, PG&E is not required to provide 33% renewable energy until 2020. Including a Light Green option would significantly increase the percentage of renewable energy used by San Francisco while not raising their electric bill. This approach has proved successful for the Marin Clean Energy (MCE) CCA.
3) Prior to procuring energy, it will be necessary to determine the power cost parameter ranges that can feasibly support the green renewable energy plan offerings. For both the 100% renewable energy and the recommended Light Green plan, the generation price points needs to be determined so that the energy procured is not too costly for the customer rate structure envisioned. Further, the maximum average energy price needs to be determined so that the City's goal of affordable renewable energy can be balanced with the City's goals for developing and utilizing local renewable power generation, leadership in renewable energy and local job creation.
4) Determination of the maximum average renewable energy cost will allow the City to maximize local renewable energy generation and local job creation while providing affordable, cost-competitive renewable energy to the City's businesses and residents. The recommended method to accomplish the City's goals is to first calculate the maximum power purchase price considering all CPSF's fiscal responsibilities (see Section 10); and then purchase the maximum amount of in-City and regional energy, balanced with less expensive non-regional, preferably California-generated, energy which allows CFSP to sell energy at a rate competitive with PG&E.

Task 2: Timing/Economic Benefits of Local Build Out

1) EnerNex recommends adopting program and management principals including lifecycle management to assist with the timing and planning of build-out efforts.
2) A fundamental consideration for expanding beyond the proposed initial 20-30MW implementation phase will be to decide whether to synchronize the build-out of local

generation projects with the expansion of the CPSF program or whether to use procured power to supply electricity needs in advance of local generation build-out. EnerNex recommends adopting program management principals including lifecycle management and lifecycle costing to optimize the timing and planning of build-out efforts.

3) The development of local renewable energy projects has the potential to realize economic benefits for the City from the employment and expenditures for implementation activities and also from the shift of spending on energy from remote sources to sources within the City.
4) To maximize local economic benefits, the City should focus on local employment and procurement provisions, and establish a preference for projects that are physically located within the City and County of San Francisco. Methods of ensuring local benefits include the imposition of local contracting, procurement and hiring requirements, and from a preference for transaction structures (such as PPAs and PPPs) that provide for the eventual ownership of generation facilities by local entities.
5) From a high level economic development point of view, two groups of projects were considered for this build-out report: a) Specific projects being considered for renewable generation including solar, wind and geothermal resources; and 2) Conceptual projects for both small hydroelectric generation and behind-the-meter (BTM) customer programs:
   a. Table 1 through Table 3 provide a listing of the solar, wind and geothermal projects being considered as well as a summary of total economic impact assuming that **all projects were constructed**[1]**.**
   b. Table 5 and Table 6 provide some insight into the potential economic impacts from small hydroelectric generation through alterations or improvements to existing hydroelectric generation and water delivery as well as behind-the-meter (BTM) customer programs including Energy Efficiency (EE), Demand Response (DR) and Distributed Energy Generation (DER) including solar.

[1] This economic impact assessment assumes a 2016 start date for construction and the definition of "local" in the model output would indicate broader regional and even state wide impacts rather than specifically within the City of San Francisco. The actual project approval and construction timing will significantly alter these high-level estimates.

Table 1 Solar Project Economic Impact Summary[2]

Project	Capacity (MW-AC)			Cost ($/M)			Construction Jobs				Operations Jobs			
	Low	Avg.	High	Low	Avg.	High	Jobs per $Million	Low	Avg.	High	Jobs per $Million	Low	Avg.	High
Warnerville Substation	25	29.8	35	$140	$173	$210	5.6	788	972	1182	0.05	6.6	8.1	9.9
Sunol Valley	13.4	17.5	20	$50	$85	$120	6.7	336	570	806	0.06	2.8	4.7	6.6
Tesla Portal	1.6	2.8	5	$6	$17	$30	12.2	67.2	205	367	0.13	0.7	2.2	3.9
SFO Parking Lot	10	10.0	10	$50	$60	$70	6.4	321	385	449	0.05	2.3	2.7	3.2
Hunters Point - Parcel E	3	6.5	10	$21	$40	$60	5.3	110	212	315	0.04	0.9	1.8	2.7
University Mound - North Basin	3	2.9	3	$15	$20	$30	5.6	83.5	113	167	0.04	0.6	0.8	1.2
Sutro Reservoir / Summit Pump Station	2	2.4	3	$11	$18	$23	5.3	58.8	94	123	0.03	0.4	0.6	0.8
Pulgas Balancing Reservoir	2.5	2.5	2.5	$14	$20	$25	5.0	70	99	125	0.04	0.5	0.7	0.9
SF Port- pier 90-94	3.1	3.1	3.1	$21	$21	$21	5.0	104	104	104	0.03	0.6	0.6	0.6
Total	**63.6**	**77.5**	**91.6**	**$328**	**$453**	**$589**		**1939**	**2754**	**3638**		**15.3**	**22.2**	**29.7**

[2] Details for the possible Solar projects are described in Section 6.1

Table 2 Wind and Geothermal Project Economic Impact[3]

Generation Type	Project	Size (MW-AC)	Capital Cost ($M)	Construction Jobs/$M	Construction Jobs	Operations Jobs/$M	Operations Jobs
Wind	Oceanside	2	$2,738	0.01	16	0.0004	1
	Sunol	30	$2,577	0.08	207	0.0027	7
	Tesla	6	$2,820	0.02	48	0.0004	1
	MontezumaHills	100	$2,043	0.24	485	0.0083	17
	AltamontPass	20	$2,349	0.06	141	0.0017	4
	WalnutGrove	170	$2,244	0.39	873	0.0125	28
	LeonaValley	100	$2,649	0.23	607	0.0064	17
	NewberrySprings	100	$2,332	0.23	543	0.0073	17
	SubTotal	528	$19,752	0.15	2920	0.0047	92
Geothermal	Brawley-Binary	50	$4,963	0.06	291	0.0026	13
	Geysers-Flash	50	$4,467	0.09	389	0.0031	14
	LongValley–Binary	40	$4,283	0.43	1830	0.0091	39
	SubTotal	140	$13,713	0.18	2510	0.0048	66
Total		**668**	**$33,465**	**0.16**	**5430**	**0.0047**	**158**

[3] Details for the possible Wind and Geothermal projects are described in Section 6.1

Table 3 Build-out Project Economic Impact Summary (Assuming ALL Projects are Constructed)

	Capacity (MW-AC)			Cost ($M)			Construction Jobs/$Million			Construction Jobs			Operational Jobs/$Million			Operations Jobs		
	Low	Avg	High	Low	Avg	High	Low	Avg	High	Low	Avg	High	Low	Avg	High	Low	Avg	High
Large Solar[4]	64	78	92	$328	$453	$589	5.0	6.3	12.2	1,939	2,754	3,638	0.03	0.04	0.05	15	22	30
Wind		528			$19,752			0.15			2,920			0.005			92	
Geothermal		140			$13,713			0.18			2,510			0.005			66	
Total		**746**			**$33,918**			**2.2**			**8,184**			**0.016**			**180**	

[4] Variance in capacity, cost and economic impact for solar project estimates due to up to three project assessments with a variety of capacity specifications and cost possibilities

Table 4 Range of Possible Economic Impact from Behind the Meter Projects (EE, DR, DER)

EE Program Funding ($Million)	Approximate Investment including customer $[5] ($Million)	Estimated Jobs Impact (6.6 jobs per $M)
2	8.3	55
4	16.6	109
6	24.9	164
8	33.1	219

[5] According to Lori Mitchell, San Francisco Water, Power and Sewer Manager Renewable Energy Generation, SoSolar SF has paid $21 Million in incentives since the program start and the private investment based on submitted total project costs is $87 Million. This is equivalent to 24.1% of project costs being provided by program funding and provides the basis for the high level Behind the Meter economic impact assessment. Whether this is a realistic assumption completely depends on subsequent program design. In comparison, MCE SmartLights program typically rebates 25%-75% of total project costs to small commercial customers and up to 100% of project costs for high efficiency lighting in multi-family dwellings.

Table 5 Range of Economic Impact Possibilities from Small Hydro and Behind the Meter Projects

Generation or Investment Category	Possible Projects	Capacity (MW-AC)		Cost ($M)		Construction Jobs per $M		Construction Jobs		Operations Jobs per $M		Operations Jobs	
		Low	High	Low	High	Low	High	Low	High	Low	High	Low	High
Small Hydro[6]	14+	0.2	53	0.1	26	0.16		0.02	4	0[7]		0	
Behind the Meter (EE[8], DR, DER)	N/A	N/A	N/A	2	8	6.6		55[9]	219[9]	0		0	

[6] Small hydro projects include a variety of alteration or improvement projects under consideration by SFPUC to increase or improve generation output (See Sections 6.2 and 12).

[7] Assumes no incremental labor to support operation of upgrades and alterations after construction

[8] Between $4-6 Million of the possible $8 EE project budget cited includes a possible CPUC approved transfer of $2-4 million of EE funding from PG&E to CPSF/SFPUC/SFE. As a result, the economic impact from the potential $4-6 Million transfer from PG&E may be a transfer of PG&E EE program economic impact to the CPSF/SFPUC/SFE EE program rather than incremental economic impact.

[9] Assumes 24.1% of project costs are covered by program funding with remaining project cost being covered by the customer consistent with the SoSolar SF program design.

A more detailed analysis should be completed before any final program decisions are made and to expand on this high-level estimation, the following information that would be required to develop a more in-depth analysis:

- **Total budget**, broken down by type of expenditure (materials and type of materials, labor costs).
- **Project schedule**. The availability and expiration of tax incentives related to renewable energy construction also has an impact on the procurement approach for determining City owned resources or privately owned resources with a lease arrangement for the City.
- **Program Design** for any Behind the Meter programs.
- **Location of expenditures** (in the City and County of San Francisco, in the SF Bay Region, in California, or outside California), broken down by type.
- **Cost of power produced,** along with assumption for cost of power without the project.
- **Tax or fee revenue generated** by the project or by end users (such as utility users tax).
- Application of any local procurement or hiring requirements.

Once the detailed and precise information for specific projects is developed, economic analysis can be performed for each option or project.

Task 3: Local Build-Out Program:

- CPSF should pursue funding of Energy Efficiency (EE) programs through the CPUC, as doing so will potentially increase funding overall for San Francisco's businesses and residents. Coordinating CPSF's CPUC-funded Energy Efficiency (EE) programs with those from PG&E's EE programs as well as those from the Bay Area Regional Energy Network (BayREN) will result in additional funding for San Francisco. After all CPUC EE funding options are fully utilized, the CPSF can consider additional self-funded EE programs. Self-funded CPSF EE programs would need to consider the impact of the EE programs versus the EE program costs which would ultimately be passed onto its customers. . CPSF customers participating in EE programs should also be informed of GoSolarSF programs.

Task 4: Energy Efficiency Strategy

1) CCA's, including CPSF, can use Energy Efficiency (EE) funds collected from their own customers as well as funds collected from the Investor Owned Utility (IOU) servicing their territory. The CPUC requires that EE programs be cost effective and lead to direct energy savings. In addition the CPUC will provide funding for unique programs proposed by CPSF that do not duplicate programs currently offered by PG&E.
2) There are tremendous resources available within the agencies in the SFPUC and the Department of Environment that can be leveraged for future EE programs. It is

recommended to coordinate planning with the BayREN and SFE to not duplicate efforts already being planned.

3) A list of possible EE programs for CPSF includes small commercial program targeting specific segments underserved by PG&E, financing for smaller commercial customers that do not meet the minimum loan requirements of PG&E's On Bill Financing (OBF) program, financing targeted at technologies that exceed the payback criteria of PG&E's OBF program.
4) CPSF expects to have $2M allocated by the City for EE improvements with priority given to low income CPSF customers. Program design details are not known for the EE incentive design such as a rebate reimbursing the homeowner, business or resident for a certain percentage of the purchase price for more energy efficient equipment. However, it is expected that the economic impact for spending on the installation of EE equipment will generate 6.6 jobs for each $Million expenditure which includes the total spent on EE improvements by both the program as well as the customer.
5) Between $4-6 Million of the possible $8 EE project budget cited includes a possible CPUC approved transfer of $2-4 million of EE funding from PG&E to CPSF/SFPUC/SFE. As a result, the economic impact from the potential $4-6 Million transfer from PG&E may be a transfer of PG&E EE program economic impact to the CPSF/SFPUC/SFE EE program rather than incremental economic impact.

Task 5: Commercial and Industrial Customers

1) The current plan calls for CPSF to offer service to residential customers only. In addition to serving residential customers, CPSF should consider offering service to commercial customers especially those businesses who have already indicated that they want to enroll in a high content renewable energy plan. Including commercial customers will significantly increase the amount of renewable energy used in San Francisco, while at the same time increasing revenue for the CPSF.
2) Commercial and Industrial (C&I) customers are "higher margin" customers that generate more revenue per bill and this is one of the reasons that we recommend that the CPSF offers service to non-residential customers in Phase 1. In addition, large customers would have a the potential for a greater impact on the City's goals for improving energy efficiency, increasing San Francisco's use of clean renewable energy and creating or supporting local jobs. Thus, large C&I customers should be encouraged to join the CPSF. Recommendations for attracting C&I customers include offering commercial EE programs, utilizing SFPUC's list of C&I customers who proactively indicated that they want to participate in a 100% renewable program, and neighborhood canvassing of business corridors.

3) The current plan is for phase 1 to serve residential customers with 20-30 MWs of renewable energy. A phased implementation process is recommended which will add additional customers and the Light Green option. For example, Phase 2 could offer service to C&I customers, and Phase 3 could add the Light Green option.

Task 6: Renewable Energy Production and Purposes

1) The cost of energy generation should be calculated using Levelized Cost of Energy (LCOE) methodology which will allow estimated costs to be compared across all sources being considered for of renewable energy within comparable time frames.
2) Existing cost estimates vary significantly for the many of the proposed renewable energy projects. Thus prior to build out, further analysis is necessary to validate the estimated cost of specific renewable energy projects. Review of existing, albeit varying cost estimates, indicates that build out of small hydro projects by the City's Water Department as well as PPAs to acquire solar and wind energy from local and regional projects are the most cost effective sources of renewable energy. For solar projects, transfer of ownership to CPSF after several years appears to be the most cost effective option. Ownership transfer of solar projects is also recommended, as it will lower risk for the CPSF.
3) Preliminary estimates of contemplated projects are provided later in this report. In general, the jobs impacts of the projects vary between two and seven jobs created per $1 million in construction, with most projects creating between six and seven jobs per $1 million and wind projects just above two jobs per $1 million. Projects also create less than one job during operation for each $1 million in construction costs. The location of the jobs essentially follows the location of the project, so projects within San Francisco will generally create local jobs while projects within the region will generally create regional jobs. A key to the economic impact analysis of the projects is their location, projects in SF and in the region will generate jobs that benefit SF and the region while projects further afield will not.
4) The small hydroelectric generation projects being considered by SFPUC include a variety of projects for alterations or improvements to existing hydroelectric generation as well as water supply and delivery. As a result, the estimated economic impact related to the small hydro projects that would need to be further refined as each project is considered for approval and implementation.

Task 7: Behind-The-Meter Deployment Strategies

1) Behind-the meter (BTM) projects promote local economic development and job creation. Further, many behind-the-meter projects would save customers money by reducing their

overall energy costs. Thus helping to fund BTM projects may attract customers to the CPSF. In order to increase investment in BTM projects, CPSF will need to offer programs that are economically beneficial to the system owners while at the same time have a neutral to positive impact on the overall economics of CPSF's program.

2) BTM projects are typically owned by their owners who are responsible for the projects, including assuming liability and risks for the systems. Accordingly, the majority of the economic benefits of BTM systems will accrue to their owners. BTM projects which are win-wins in that they benefit both the system owners and the CPSF include Demand Response (DR) projects and purchasing excess generation from customer-owned systems.
3) In order to increase investment in BTM projects, CPSF will need to offer programs that are economically beneficial to the system owners while at the same time have a neutral to positive impact on the overall economics of CPSF's program.
4)

TASK 8: GOSOLARSF INCENTIVES AND PROJECTS

1) Coordination of CPSF projects with the GoSolarSF program would leverage funding and would increase benefits for CPSF customers. CPSF marketing materials can and should list all programs available to CPSF customers, including GoSolarSF.
2) CPSF could eventually fund a portion, if not all of the GoSolar program, by integrating GoSolarSF into the overall CPSF local resource build-out plan and supporting all/part of the cost of the program through a portion of revenue from CPSF sales.

Task 9: Net Energy Metering Tariffs

- A favorable Net Energy Metering (NEM) tariff is recommended as it would attract existing solar customers to the CPSF. Reimbursing CCA customers at a higher rate than PG&E pays for customer-generated renewable energy would both encourage solar owners to join the CPSF and would increase CPSF's use of local renewable generation. Implementing net metering tariffs would not be difficult.

Task 10: Financing Support

1) A CCA's financial strength is critical to its long-term viability and its ability to access financial markets. Financial markets will play a critical role in CPSF ability to issue future debt and the cost it pays for this debt. The early establishment of sound financial policies and practices will be key in the success of the renewable program.
2) The stability of CPSF's customer base will impact the financial market's assessment of the systems revenue stability. However, as the customer base of the CPSF is anticipated to be largely residential, the risk of substantial fluctuations in revenues associated with the loss

of volume sales should be minimal resulting in a favorable assessment by the financial markets.

3) Demographic and usage characteristic are also an important factor in assessing revenue stability. Based on the demographics and anticipated usage characteristics of the CPSF customer base, the risks associated with substantial fluctuations in revenues should be minimal and, therefore, viewed favorably by the financial markets.
4) CPSF should establish policies to ensure the electric utility maintains appropriate financial margins, including debt service coverage and operating reserve levels. Broad and specific financial policy objectives are outlined in Section 10.1 and key financial metrics are provided in Table 45.
5) To the extent the CPSF's power portfolio includes purchased power, rate mechanism(s) should be developed to mitigate the financial risks specifically associated with fluctuations in the costs of purchased power. The industry utilizes several alternatives to address this issue and it is recommended the CPSF evaluate these alternatives to determine which best meets the goals and objectives of the electric utility.
6) It is recommended CPSF develop an Integrated Resource Plan (IRP) to assist in meeting forecasted annual demands, including both peak and an established reserve. The IRP should evaluate the full range of alternatives, including new generating capacity, power purchases, energy conservation and efficiency, to provide adequate and reliable service at the lowest system cost.
7) CPSF should assess its ability to maintain competitive rates as a means to mitigate the risk associated with the potential migration of customers to service areas where lower cost power is available. The assessment should consider the potential impact of the long-term capital program and required funding.

Task 11: Feed-In Tariffs and Power Purchase Agreements

1) Competitive bidding processes for Power Purchase Agreements (PPAs) are commonly used by CCA's including MEA, SCP and Lancaster's Choice Energy as the primary vehicle to procure longer-term, structured energy supplies from the market[10]. Market solicitations through Request for Proposal or Requests for Bid/Offer are the most common approach

[10] For purposes of this section, we are associating Power Purchase Agreements (PPAs) with longer-term structured transactions with potentially customized terms and conditions as opposed to shorter-term (e.g. Day Ahead, Week Ahead, Month Ahead, etc.) market purchases that may be transacted under a Master Service Agreement (essentially an overarching PPA) where the terms and conditions are established and not renegotiated for each individual transaction.

used by market participants to purchase non-renewable as well as renewable energy at the lowest available price. Responses to solicitations may include production from a specific generation resource or may be offered as a "system" sale of the specified products and services.

2) Feed-in tariffs (FIT) offer key benefits to CPSF which include the ability to acquire local clean renewable energy at stable prices under multi-year contracts. Further local projects will offer opportunities for local jobs and the potential for money spent on energy to remain in the local economy. Another benefit is that long-term contracts typically used offer price stability for the CPSF as well as stable long-term return on investment for the renewable system owners.

Task 12: Hydroelectric Generation

1) Working with the SFPUC and Commission, it should be possible for CPSF to become a customer that receives priority for Hetch Hetchy power after the current municipal customers including city buildings, SFO, SF hospital, police, fire, and MUNI vehicles and the retail customers at Hunters Point and Treasure Island.
2) Review of existing, albeit varying cost estimates, indicates that build out of small hydro projects by the City's Water Department as well as PPAs to acquire solar and wind energy from local and regional projects are the most cost effective sources of renewable energy.

The remainder of this report presents detailed descriptions and recommendations defining the next steps necessary to proceed with planning the build out of CPSF's CCA program.

INTRODUCTION

Pursuant to California State Assembly Bill 117, the City and County of San Francisco (City) has been investigating various approaches to becoming a Community Choice Aggregator (CCA) that would provide electric power and a broad range of related benefits to the citizens and businesses located within the City.

The CCA Program, CleanPowerSF (CPSF), as currently designed will offer the option of 100% renewable power, which would meet or exceed requirements established by the California Public Utilities Commission (CPUC) for Load Serving Entities (LSEs) for compliance with the Renewable Portfolio Standard (RPS). The reassessment or “resetting” of the CPSF program, which includes the evaluations and recommendations within this report present an opportunity to question original program design assumptions. For example, option that should be considered by the CCA is a “Light Green” plan that offers less than 100% renewable energy. For example, CPSF could offer a Light Green option similar to Marin Energy Authority’s Light Green plan that offers 50% renewable energy at rates lower than standard PG&E rates.[11]

CPSF will also fully comply with all other regulatory requirements including but not limited to those pertaining to Resource Adequacy (RA), and Greenhouse Gas Emissions (GHG). Part of the renewable power portfolio may be made up with Category 3 renewable energy certificates (RECs), with the goal of the underlying energy coming from non-nuclear carbon-neutral sources.

A cornerstone and integral component of the CPSF program is renewable technology selection and site identification, build-out and integration of in-city/city adjacent clean energy generation projects and energy efficiency programs. The local clean renewable energy obtained through the build-out will be incorporated into the CPSF energy supply portfolio and will be used to meet the continuing needs of CPSF customers as the program builds and expands. One of the initial goals of the CCA Program is to provide 50% or more of the CPSF customer energy use through a combination of local and regional renewable generation sources in conjunction with reducing customer energy use through energy efficiency efforts within the first 10 years of the program. Achieving the 50% local renewable/energy efficiency goal must be done in a cost effective manner and it likely will be necessary to balance the acquisition of clean local renewable generation with the goal of offering energy at competitive rates.

A key tenet of the CPSF program is that it be self-funded, primarily from revenues obtained through the sale of green energy to end users and from energy efficiency funds available from programs administered by the CPUC. To establish a CPSF customer base and get revenues flowing, CPSF developed a short-term energy procurement strategy that would enable a renewable electric supply portfolio option for customers built primarily from market purchases

[11] MCE Light Green 50% Renewable Energy Program, http://www.mcecleanenergy.org/50-renewable/

of qualified renewable energy products. To the extent that there was any surplus energy and/or capacity available from SFPUC's existing municipal generation system[12], that supply could be integrated into the CPSF portfolio as well.

The first phase of CPSF is planned to have between 20-30 MW of customer load[13]. The initial load would be served by clean renewable electricity delivered to residential and/or commercial customers, with the expectation that some of the build-out of local generation and efficiency installations would begin during the first phase. Under the current program design, approximately 90,000 residential customers are included in the first phase. The timing of future phases will be influenced by both the success of Phase 1 and the speed of build-out of new energy resources that would be added to the CPSF supply portfolio and used to support the growing customer base.

The San Francisco Local Agency Formation Commission (LAFCo) was authorized[14] by the San Francisco Board of Supervisors (BoS) to:

- Monitor the CPSF startup and implementation process
- Advise the BoS and SFPUC of progress and
- Work with the SFPUC in the creation of a successful CPSF program.

CPSF is administered by the SFPUC specifically within the Power Enterprise (PE) department. To support CPSF Phase 1, the SFPUC initially decided to use a third party to procure the renewable energy and manage the CPSF supply portfolio. SFPUC built a staff within SFPUC to administer the CPSF program. It was envisioned that SFPUC would eventually take over the supply and portfolio management functions initially provided by the third party supply as the CPSF program evolved and grew.

EnerNex was engaged by LAFCo to work with the SFPUC, PE and CPSF to develop a detailed plan for the renewable energy build-out that is manageable, affordable, achievable and consistent with the goals established for CPSF. EnerNex's partner Willdan was also engaged to explore Energy Efficiency opportunities as well as assess the economic impact of CPSF build-out and implementation.

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[12] Hetch Hetchy Project: Holm(165MW), Kirkwood(115.5MW), Moccasin(100MW), Small Hydro(~4MW), solar(~7.6MW) and biogas(~3.1MW)

[13] The estimate of 20-30 MW of customer load in the initial phase of the CPSF program was largely based on the initial power supply contracting strategy with Shell Energy North America (SENA). The "resetting" of the program which includes having SFPUC PE manage the CPSF supply portfolio may introduce the opportunity to increase the initial program size, within constraints of doing so using only existing capability and capacity of SFPUC PE staff and operations. Determination of the potential incremental increase in initial program size is beyond the scope of this report but is identified as a key action item for SFPUC PE and CPSF to examine when the program moves forward.

[14] S.F. Ordinance 146-07, Section (b). Passed on June 6, 2007.

Many additional steps and actions are needed to actually launch CPSF as a CCA. The key steps are illustrated in Figure 1.

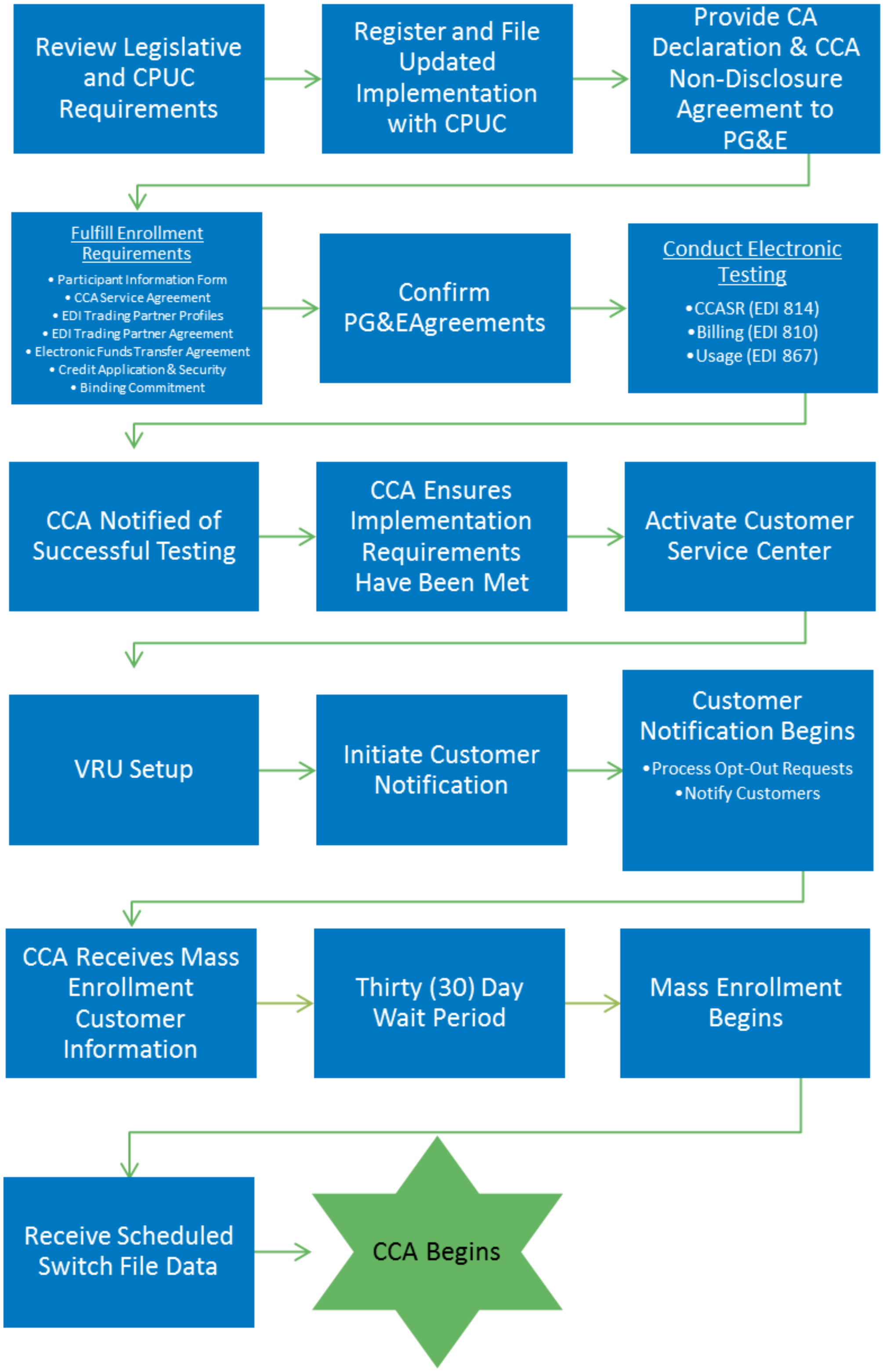

Figure 1: Overview of Key Steps In Establishing CCA Service

Referencing Figure 1, CPSF has successfully completed the first two steps to form a CCA. However, an updated Implementation Plan will need to be filed with CPUC in order to proceed with CCA rollout. The scope of this document addresses the following specific issues related to CCA Operations:

1) **CPSF to SFPUC Procurement Transfer**
   a. SFPUC Power Procurement Evaluation:
      i. Evaluate SFPUC's ability, financially and structurally, to purchase power on the open market without first designating a third party provider. Assess whether this option would be consistent with true power enterprise function. Determine capacity needs.
      ii. Analyze whether additional staff would be needed to proceed without a provider and determine whether specialized expertise will be required.
      iii. Qualitatively determine whether this option provides any financial benefits, economies of scale, or efficiencies to the City and County.
   b. Third Party Power Procurement Evaluation:
      i. Evaluate whether and to what extent third party agents may or should be used to procure energy.
      ii. Evaluate whether or not there are multiple options available in terms of proceeding without a power provider.
   c. Develop Plan for Procurement Services: If necessary, develop a plan for power procurement services. Evaluate whether an RFP or another process is needed.
2) **Timing/Economic Benefits of Local Build-out**
   a. Local Build-out Objectives: Plan installations, products, services, and purchasing strategies that achieve local build-out objectives in both the short and long term, including program and project funding mechanisms. Estimate economic benefits of planned and contemplated projects based on location and budget. Analyze specific economic benefits of each option moving forward.
   b. Plan for Substitution of Local Power Supplies: Develop plans, metrics and a cost-effective process for planned local power supplies to replace other market-purchased power. As the amount of solar PV that can be built on city rooftops is limited due to small amount of suitable rooftop space, other options including buying power from developers on non-city land and small hydro projects will need to be considered.
   c. Expand CPSF Customer Base: Develop an assessment of how and when to expand CPSF's customer base as new local and regional electricity generation facilities are brought online. After determining the cost goals for energy, and how much local/regional energy can be incorporated, RFPs can be issued to procure the energy.

d. Compare Planned to Actual Build-out: Develop plan for assessing actual real-time achievement of local build-out installations in comparison to initial plans and adjust ongoing program plans accordingly.

3) Local Build-out Program

a. Energy Efficiency Outreach: Coordinate with SFPUC's outreach staff to ensure CPSF marketing and "opt-out" materials provide information about energy efficiency opportunities available to CPSF customers.

b. Coordination with GoSolarSF: Coordinate with GoSolarSF regarding installations of solar and energy efficiency improvements on identified properties.

4) Energy Efficiency Strategy

a. Leveraging Initial Allocation: Develop plan for low income programs and priorities leveraging initial allocation.

b. Priorities and Resources: Assess whether and when CPSF will have resources for other energy efficiency programs and projects, and establish priorities for use of funds

5) Commercial and Industrial Customers

a. Attracting Commercial Customers: Assess how CPSF should use energy efficiency program offerings as a way to attract commercial customers.

b. Pilot Programs for Commercial Subsidies: Plan a pilot program with SFE that would identify candidates for subsidized commercial energy efficiency improvements as inducement for becoming CPSF customers.

c. Demand and Resource Adequacy: Determine whether and how CPSF could manage demand and resource adequacy with cycling programs and other on-site control technologies.

d. Existing Programs and Connections: Develop a plan to leverage existing programs and other agencies' community connections to make efficient use of limited resources.

6) Renewable Energy Production and Purposes

a. Identification of Potential Sites: Work with SFPUC Power Enterprise staff (e.g. Renewables group, Energy Efficiency group) to develop a plan for identifying potential sites for build-out with initial focus on exiting site selection list.

b. Evaluate Small Hydro Investments: Evaluate potential for CPSF to invest in small hydroelectric power programs. Develop an analysis of economic benefits for CPSF and its ratepayers.

c. Evaluate Potential for Sunol Solar Project: Determine whether a solar project in Sunol would be a cost-effective investment for CPSF customers. Determine what future steps are necessary if the solar project is cost-effective. After determining the cost goals for energy, and how much local/regional energy can be incorporated, RFPs can be issued to procure the energy.

d. Investigate Ratemaking Policies: Investigate prospects for petitioning the CPUC to change the ratemaking policy that requires CCA customers to pay for transmission services they do not use.

7) **Behind-the-Meter Deployment Strategies**

a. BTM Feasibility Analysis: Analyze the prospects for supporting Behind-the-meter (BTM) projects using revenues from bonds and CPSF's capacity for related project and program management.

b. Three Year Financial Plan: Determine how much of CPSF's initial funding and future revenues from customer billings should be used to support BTM projects in the first three years of operation.

c. BTM Installation Planning: Evaluate future steps that will be necessary to install BTM installations utilizing the desired terms.

d. Attracting Customers Through BTM Subsidies: Determine if and how BTM subsidies should be used as a mechanism to of attract new CPSF customers.

8) **GoSolarSF Incentives and Projects**

a. Siting Criteria: Work with the GoSolarSF group to develop a set of criteria for evaluation of potential CPSF sites for solar installations.

b. Potential through Low Income Properties: Coordinate with the GoSolarSF group and SFE to develop plan for identifying ideal project candidates at low income properties, and other sources of project support, whether from property owners, CPSF customers or government-sponsored programs.

c. Pre-construction Evaluation: Determine the next steps for solar installation before construction commences.

d. Project Progress: Develop plan for monitoring project progress and when relevant, establish sales agreements. Develop monitoring criteria and a plan for sales agreements.

9) **Net Energy Metering Tariffs**

a. SFPUC NEM Tariff Plan: Draft a plan for the development of a Net Energy Metering (NEM) tariff.

b. Identifying NEM Participants: Develop plan for identifying potential NEM participants in all areas of the City and develop a plan to notify them of any NEM tariff offering.

10) **Financing Support**

a. Issuing Bonds/ Renewable Project Financing: Develop a plan for issuing bonds for types of projects. The plan should be integrated on a timeline that minimizes risk. Investigate opportunities for financing of renewable projects by leveraging existing programs or helping to support the development of new ones.

b. Direct Support of Individual Project Development: Investigate whether CPSF can directly support individual project development with financial support mechanisms as contract components.

11) Feed-In Tariffs and Power Purchase Agreements

a. Power Purchase Agreements: Prepare an analysis of a competitive bidding process that would use winning bidders to sell power to CPSF according to negotiated Power Purchase Agreements (PPAs), which may include terms tailored to the needs CPSF and/or the specific project.

b. Feed-In Tariffs: Develop a plan addressing feed-in tariffs for power purchases from renewable resources in the City. This plan should address the benefits of the options to CPSF.

12) Hydroelectric Generation

a. Use of Hetch Hetchy: Develop a plan for future steps that would be necessary for CPSF to take available excess power supply from Hetch Hetchy, including the need to account for yearly fluctuations in available Hetch Hetchy power.

b. High Priority Customer: Work with SFPUC Power Enterprise staff to determine whether CPSF can be a high priority customer through the long-term operations.

c. Small Hydro: Evaluate prospects for CPSF development of “in-pipe” small hydroelectric facilities (for example, University Mound).

Each of these issues was addressed as a Task in the review and evaluation process used to develop this Build-Out Plan. The remainder of this document presents the results of our review and evaluation in each Task area and includes a statement of Key Findings related to each Task.

1 TASK 1: UTILIZING SFPUC FOR CPSF POWER PROCUREMENT

EnerNex was engaged to perform a high-level initial assessment to:

- Assess SFPUC's ability to procure and manage the supply portfolio for CPSF;
- Evaluate whether and to what extent third party agents may or should be used to procure energy; and
- Develop Plan for Procurement Services.

The following sub-sections address each of these three questions.

1.1 SFPUC Power Procurement Evaluation

The first task (Task 1.0) identified in the scope of work for the CPSF build-out plan included a high level evaluation of SFPUC's current ability and capacity to fully manage the procurement and supply portfolio for CPSF Phase 1 as an option to having a third party provide those services as was originally envisioned.

Specifically, the SFPUC Power Procurement Evaluation scope of work consisted of three subtasks:

Subtask A: Evaluate SFPUC's ability, financially and structurally, to purchase power on the open market without first designating a provider. Assess whether this option would be consistent with true power enterprise function. Determine capacity needs.

Subtask B: Analyze whether additional staff would be needed to proceed without a provider and determine whether specialized expertise will be required.

Subtask C: Qualitatively determine whether this option provides any financial benefits, economies of scale, or efficiencies to the City and County.

The Task 1 evaluation and assessment was fast-tracked so that the findings could be considered and, if warranted, incorporated into SFPUC's June 2014 budget hearings. By necessity, gathering, review and assessment of relevant information, took place within a 1-week period. EnerNex utilized materials provided by LAFCo and SFPUC staff as well as documents and other data that were available in the public domain[15]. EnerNex also had an opportunity to meet once with key SFPUC Power Enterprise (PE) and LAFCo staff[16].

A report detailing the results of Task 1.1 from the initial fast track assessment was completed and delivered on May 15, 2014. This report incorporates those findings.

The purposes of the initial assessment Task 1 were to:

- Evaluate San Francisco Public Utility Commission's (SFPUC's) ability, financially and structurally, to purchase power on the open market without first designating a specific provider.
- Evaluate whether or not there are multiple options available in terms of proceeding without a specified power provider.
- Analyze whether additional SFPUC staff would be needed to proceed without a provider. Determine whether specialized expertise will be required.
- Determine whether the SFPUC option provides any financial benefits, economies of scale, or efficiencies to the City and County, including assessing whether the option to have SFPUC PE provide these services would be consistent with true power enterprise function.

Assessment findings are presented for each of the three sub-tasks in the following sub-sections:

1. Assess Ability to Procure and Manage CPSF Supply Portfolio
2. Assess Staffing Needs
3. Assess Potential Benefits, Economies or Efficiencies

1.1.1 Subtask A: Assess Ability to Procure and Manage CPSF Supply Portfolio

Current Role and Capability

The SFPUC PE manages the operation and commercial market activities associated with the City's Hetch Hetchy Power System (HH) which consists of hydro generation plants and power transmission lines. PE also manages energy produced from solar and biogas generation facilities

[15] LAFCo and SFPUC web sites, video records and agenda materials from LAFCo, SFPUC, and Environment Commission meetings. See Appendix A for a list of the major documents and sources.

[16] May 5th 2014 at 525 Golden Gate Ave. In attendance from SFPUC PE were John Doyle, Pamela Husing, Lori Mitchell and Kim Malcom., Jason Fried (LAFCo), Nancy Miller (LAFCo) were also in attendance.

located within the City. The PE generation portfolio is almost 400 MW and is 99% greenhouse gas emission free[17].

PE operates and manages the HH generation portfolio consistent with the requirements of the Raker Act[18], which specifies that power must be sold to municipalities, municipal water districts or irrigation districts. HH generation first serves the needs of SFPUC's municipal and retail customers. Any available excess HH power is then allocated to the Modesto and Turlock Irrigation Districts (MID & TID) up to the limit of their agricultural and municipal loads. Currently, TID has a contract which allows them to take up to 50% of TID's share of the first 100 MW of available HH excess offered to airport tenants. HH power cannot be sold to entities for resale (i.e. profit). Currently excess power is sold to other qualifying public power providers and public entities at prevailing wholesale market rates. Typically, when there is excess hydroelectric generation, the prevailing wholesale market prices[19] tend to be lower due to an excess of supply. If the energy cannot be stored (through storage of water) then the alternatives are to spill the water or generate electricity and capture whatever revenue the prevailing wholesale market price provides. If SFPUC PE had an incrementally larger customer base[20] served at a fixed electric supply rate (i.e. CPSF retail customers), those customers would essentially represent a "put" where SFPUC PE could direct any available surplus hydro generation and subsequently generate revenues at a higher margin that might be realized in available wholesale markets.

PE manages a supply portfolio that serves about 2,600 retail and wholesale customers, historically with a fairly high load factor of 60-70%. However, HH supply is weather dependent and peaks in the spring with the snow melt and runoff, thus in normal years generates more energy than is required by PE's customer load.

PE manages an interconnection agreement (IA) with Pacific Gas & Electric Company (PG&E) that includes a banking provision which facilitates managing the seasonal HH output variations and effectively hedges market price risk. The PG&E IA also isolates PE from the CAISO transmission and congestion charges. In the summer and fall, HH generation is often not sufficient to meet PE's customer load necessitating the use of the banking feature in the PG&E IA, and at times, the purchase of power from the market. The PG&E IA agreement expires in 2015 and is currently

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[17] SFPUC's Hetch Hetchy Power system includes 384.5 MW of hydro, 7.5 MW of PV and 3.1 MW of biogas generation plant, thus 99% of the SFPUC generation plant is greenhouse gas emission free (392 MW out of 395 MW).Source: "Hetch Hetchy Power System – Generating clean energy for San Francisco", http://www.sfwater.org/modules/showdocument.aspx?documentid=4202

[18] Text of the 1913 Raker Bill: http://www.sfmuseum.org/hetch/hetchy10.html

[19] This is typical of real time, Day-Ahead and short term OTC wholesale energy markets in CA.

[20] The City is constrained by terms of the Raker Act that define they type of power sales that are allowed. CPSF customers are assumed to be City customers and thus would have a priority call on the energy produced by the Hetch Hetchy system.

being renegotiated. Without the current banking option, an agreement with CPSF to utilize the excess generation could potentially increase revenue from the excess hydroelectric generation compared to selling excess to the wholesale electricity market as discussed above.

PE is responsible for load forecasting for its municipal (general fund and Enterprise) and other retail customers within the City. PE performs short term (daily, weekly, and balance-of-month) and long term load forecasting and develops plans for selling excess HH generation when it is available and for procuring power from the market when available HH power cannot meet all the PE customers' load. In dry years and in seasons when HH generation output is not sufficient to meet PE load obligations, PE is responsible for developing an energy procurement plan and managing market risk as energy purchases and sales are executed to serve load.

PE produces forecasts and preschedules but utilizes the services of APX to act as PE's CAISO Scheduling Coordinator. The APX contract expires in 2015. PE also manages all Meter Data Management functions for PE's existing customers and manages settlements with CAISO, wholesale customers and market participants.

PE manages the supply portfolio to achieve Renewable Portfolio Standard (RPS) compliance, including management of Renewable Energy Credits (RECs), as well as fulfilling all regulatory compliance and reporting obligations. RECs are categorized by location and delivery mechanisms as shown in Figure 2. Part of the renewable power portfolio may be made up with Category 3 renewable energy certificates (RECs), with the goal of the underlying energy coming from non-nuclear carbon-neutral sources.

RPS Portfolio Content Categories	Definition	Examples
Category 1 procurement is: Procurement of Energy and RECs delivered to a California balancing authority (CBA) without substituting electricity from another source	• Energy and RECs from an RPS-eligible facility that is directly interconnected to the distribution or transmission grid within a California balancing authority area (CBA); or • Energy and RECs from an RPS-eligible facility, that is not directly interconnected to a CBA, but is delivered to a CBA without substituting electricity from another source; or • Energy and RECs dynamically transferred to a CBA.	1. Wind facility in Washington state delivers Energy and RECs with firm or non-firm transmission according to an hourly or sub-hourly schedule 2. Biomass facility directly interconnected to CAISO delivers Energy and RECs
Category 2 procurement is: Procurement of Energy and RECs that cannot be delivered to a CBA without substituting electricity from another source	• Buyer simultaneously purchases Energy and RECs from an RPS-eligible facility, where the energy must not be already committed to another party, without selling the energy back to the generator; • Renewable generation is firmed and shaped with substitute electricity that is scheduled into a CBA within the same calendar year as the RPS generation; and • Substitute electricity provides incremental electricity to the buyer.	1. Buyer procures Energy and RECs from Wind facility in Oregon; renewable Energy is firmed and shaped by third party; substitute electricity is delivered to buyer; RPS credit equals the volume of RECs generated by wind facility
Category 3 procurement is: Procurement of unbundled RECs only, or RECs that do not meet the conditions for Category 1 and 2	• Unbundled RECs originally associated with generation from an RPS-eligible facility (i.e., no Energy procured); • Unbundled RECs that do not qualify under the criteria of Category 1 and 2.	1. Buyer procures unbundled RECs from RPS-eligible facility (could be from a wholesale generating facility or a customer-owned facility) 2. A Category 2, firmed and shaped transaction, where some of the substitute electricity is not scheduled in the calendar year of the RPS-eligible generation

Figure 2 California Renewable Energy Credit Categories

PE has an approved Energy Trading Risk Management Policy (ETRMP) in place that applies to energy transactions that will:

1) Commence delivery within 6 months of the agreement date,

2) Have delivery duration of less than one year and

3) Have a transaction value of less than $500,000.

The ETRMP policy documents PE's risk management policies and procedures for limited trading activity and complies with requirements of FERC Order 741 and the CAISO Minimum Participation Requirements.

Potential Expanded Role & Implications

SFPUC Power Enterprise is currently performing most, if not all of the power procurement and portfolio management functions that would be required to support the CPSF supply requirements. PE forecasts load, plans for short and long term resource needs, evaluates market conditions, develops strategies for and executes the purchase and sale of energy products (energy, capacity, ancillary services), schedules delivery, manages the PG&E IA, and monitors/manages risk exposures associated with the portfolio. The PE staff has experience serving retail customer load (shaped) as well as working experience in the California and Western Regional wholesale energy markets.

Providing these same services for an initial incremental 20-30 MW of load, or 7.5% of the 400 MWs of SFPUC's current generation capacity, is well within PE's existing organizational capability, processes and current systems. Upcoming operational changes and challenges are all aligned with and complimentary to PE managing the CPSF supply portfolio including:

- Expiration of the PG&E IA and the TID long-term power sale agreement
- Internal programs planned and/or underway such as:
  - Replacement of the current Energy Trading and Risk Management (ETRM) system; and
  - Evaluation of alternative Scheduling Coordinator services with expiration of the contract with APX; and
- PE's pursuit of growth of in-City retail load customers.

PE has or will be developing the base skills and expertise necessary to develop a procurement plan consistent with CPSF needs and planned growth and is well positioned to build a supply portfolio that may take advantage of, but not necessarily be dependent upon, available HH power in conjunction with market purchases and incorporation of new renewable generation resources brought on line through the build-out process. In fact, PE may have an advantage over a third party procurement services provider in this area by providing highly integrated and optimized planning for and integration of renewable energy resource additions. The potential advantage arises from the flexibility and ability to trade off and modify the program as it evolves without being constrained by contract terms with a third party supplier. Providing this type of flexibility in a long-term contract with a third party provider would likely require a price premium and even then may still present challenges and contractual change orders if the program needed to change substantially[21].

Financially, PE should be able to incorporate providing procurement and portfolio management services for CPSF without encumbering or imposing a financial burden on PE. To the extent PE requires collateral to support market transactions for CPSF, CPSF would have to make that collateral available. It is reasonable to assume that the existing funds set aside as collateral under the old SENA contract would be sufficient to meet PE's requirements for conducting transactions in the market. PE may also be able to commit to a portfolio consisting of shorter term products, particularly at the program's start, which could potentially reduce cash collateral requirements, perhaps by as much as 50%. Specific collateral required will be a function of CPSF's portfolio strategy and design, and would be developed and negotiated as a part of a Memorandum of Understanding (MOU) between PE and CPSF for procurement services.

PE will need to review and likely revise the current Energy Trading Risk Management Policy and related procedures. With the expiration of the PG&E IA and the ending of the TID long-term contract, the number, frequency and types of market transactions may evolve. In the meeting with PE staff, they acknowledged that the current policy was a starting point and it would need to evolve. In particular, as more retail load is acquired, through CPSF as well as through PE's own efforts to serve more in-city retail customers, effective open position risk (volumetric and price) management, transaction monitoring, position management and reporting will be more important, and will be critical to supporting a firm transfer price to CPSF. The planned replacement of the current ETRM system in 2015 will facilitate expansion and implementation of trading risk management policies and procedures.

CPSF is intended to be a self-funded program and as such PE should be compensated for the procurement and portfolio management function. Even if there is no immediate need to expand PE staff to provide CPSF with these services (see more detailed discussion in "Subtask B: Assess Staffing Needs" below), a transfer price or some other mechanism should be established to provide appropriate compensation for services rendered.

Compensation Methodology for Estimated Payments to PE

Compensation for PE services is reasonable as CPSF would most certainly have to compensate a third party for these services. Compensation for services is most commonly embedded in the

[21] As an example, one of the typical contract structures used by third party procurement and portfolio management services providers is a defined load shape with fixed volume guarantees. If more or less energy is used, due to program growth changes differing from expected, then the CPSF would be at risk for the incremental power. In the case of opt-out or slow growth, CPSF would be at risk for the difference between the contract price and the price the third party gets for "liquidating" the excess. Managing incremental power in-house would allow for more flexibility as program conditions change.

price charged. Various methods can be used to compensate PE for services provided to CPSF for their power procurement and portfolio management services on behalf of the CPSF program. As examples, we calculated potential fees that could flow to PE using 3 different compensation approaches. Three approaches were developed to estimate revenues that should flow from the CPSF program to SFPUC Power Enterprise as compensation for procurement and portfolio management services that Power Enterprise would perform instead of a third party supplier. The best approach (which may be a combination of each of the examples or some other methodology) can be selected once the scope of services requested from PE are finalizes and the CPSF has been given approval to move forward. The level of compensation presented in the following discussion is based on an assumed initial CPSF program size of 20-30 MW. As previously mentioned, the estimate of 20-30 MW of customer load in the initial phase of the CPSF program was largely based on the initial power supply contracting strategy and the cost impact of credit security required by Shell Energy North America (SENA). The "resetting" of the program which includes having SFPUC PE manage the CPSF supply portfolio may introduce the opportunity to increase the initial program size, within constraints of doing so using only existing capability and capacity of SFPUC PE staff and operations. Determination of the potential incremental increase in initial program size is beyond the scope of this report but is identified as a key action item for SFPUC PE and CPSF to examine when the program moves forward.

The compensation approaches being considered are:

- **Approach 1** uses staff costs based on an estimated percentage of hours for each staff member to support CPSF tasks.
    - Allocation of Power Enterprise applicable staff costs using an estimate of the percentage of time each FTE would spend on direct and indirect wholesale and retail power services in support of CPSF.
- **Approach 2** calculated costs based on the ratio of electricity used by the CPSF versus the total amount available from Hetch Hetchy and other sources
    - Allocation of Power Enterprise applicable staff costs as a ratio of CPSF transaction volume (kWh) managed to the total Power Enterprise transaction volume (kWh).
- **Approach 3** used a market based approach of avoided costs using a set fee per unit of electricity served
    - Compensation Value based on an assumption of "avoided cost", which is a reasonable approximation for the value provided. For example, while difficult to get accurate price transparency for these types of services, a high-level estimate of a typical service premium of $0.0020/kWh to $0.004/kWh could represent roughly $500,000 to $1,100,000 per year in "service fees" flowing to PE for providing this critical work. Estimated service fees represent the value of similar

services that would be provided by a third party and thus would be avoided by using in-house resources.

- *Approach 1 Compensation Methodology*

Approach 1 allocated applicable PE staff costs using an estimate of the percentage of time each FTE would spend on direct and indirect wholesale and retail power services in support of CPSF. Estimated hours for each staff member were calculated on an average daily basis. Using the Class Codes and billing rates for each staff member, and the estimated hours that would be spend performing tasks for the CPSF, the effective cost of the PE's services was determined.

As is the case for all 3 compensation approaches, costs were calculated for the first full year of the CPSF program[22]. Using this approach, we estimated approximately $800,000 per year in fees would be paid to PE. If the initial CPSF program size increases from the assumed 20-30 MW, then the level of compensation would increase as more PE staff time would likely be allocated to CPSF activities. Determining the potential incremental increase in initial program size was beyond the scope of this report but is identified as a key action item for SFPUC PE and CPSF to examine when the program moves forward.

Power Enterprise staff identified 11 existing positions within the department that would likely provide services to CPSF if a third party procurement supplier was not used. We used the Class Codes for each position and the effective Hourly Billing Rate[23] for each position from the information provided from Power Enterprise and shown in the table below:

Power Enterprise Billing Rate	Class	Total Annual Comp(1) $	Annual Salary $	Annual Fringe(2) $	Annual Overhead(3) $	Hourly Billing Rate(4) $/hour
Manager III	**0931**	**271,297**	132,340	59,553	79,404	**130.43**
Manager V	**0933**	**314,097**	153,218	68,948	91,931	**151.01**
Utility Specialist	**5602**	**251,203**	122,538	55,142	73,523	**120.77**
Regulatory Specialist	**5620**	**210,002**	102,440	46,098	61,464	**100.96**

(1) Total Annual Comp = Annual Salary + Annual Fringe + Annual Overhead
(2) Annual Fringe at 45% of Annual Salary
(3) Annual Overhead at 60% of Annual Salary
(4) Billing Rate = Total Annual Comp / 2080 hours

Figure 3: Power Enterprise Staff Costs[23]

Reviewing the position titles, we made estimates of the amount of time each position would spend on activities to support CPSF. Staff mentioned that early stages of the program would

[22] Example developed assuming CPSF first full year forecast sales volumes derived from August 13, 2013 SFPUC Finance Proposed Not-to-Exceed Rates presentation, page 3. Procurement cost in Year 2 was given as $22,280,000 at an Average Rate of $0.0807/kWh. This implies a volume of 2,760,263 kWh ($22,280,000/$0.0807/kWH).

[23] Rates reflect information provided in May 2014.

require minimal amount of their time so these estimates are based on CPSF's first full year program volume[24]. The following table provides the results:

Class Code	Position Title	Role	CPSF Allocation		Annual Cost	"Hours per Day"
0933	Manager V	Electric Wholesale and Retail Services (strategic/management)	30%	$	94,229	2.4
0931	Manager III	Purchasing and Scheduling (oversee daily operations)	30%	$	81,389	2.4
5602	Utility Specialist	Purchasing and Scheduling (scheduling)	25%	$	62,801	2
5602	Utility Specialist	Purchasing and Scheduling (purchasing)	25%	$	62,801	2
0931	Manager III	Energy Trading Risk management and Settlements (risk management/settlements)	30%	$	81,389	2.4
5602	Utility Specialist	Energy Trading, Risk Management and Settlements (forecasting/risk management/settlements)	25%	$	62,801	2
5602	Utility Specialist	Retail Services (meter data management/ISO data submission)	15%	$	37,680	1.2
0931	Manager III	Energy Data Systems Manager (reconfiguration/integration changes needed for implementation)	20%	$	54,259	1.6
0931	Manager III	Reg/Leg affairs (regulatory compliance)	15%	$	40,695	1.2
5603	Utility Specialist	Specialist, Reg/Leg Affairs (RPS compliance)	20%	$	50,241	1.6
0933	Manager V	CCA Director (coordinate re program design/goals/load projections)	60%	$	188,458	4.8
11	**FTE Positions**		**Annual Total:**	**$**	**816,743**	

CPSF Year 2 Sales:		**276,084,263**	kWh
Effective Cost for Power Enterprise Procurement & Portfolio Management Services:	**$**	**0.00296**	$/kWh

Figure 4: Allocation of Power Enterprise FTE to CPSF Activities by Time Spent[23]

The allocated annual cost of $816,743 is spread over the forecast first full year of CPSF program volume of 276,084,263 kWh, resulting in a transfer rate of $0.00296/kWh.

The assumptions for allocated time were developed based on very limited organizational data from PE and combined with our internal experience. Thus, the allocations shown in Figure 4 are subject to further refinement and must be examined and reviewed through detailed discussion with Power Enterprise as the program is further refined.

- *Approach 2 Compensation Methodology*

Approach 2 allocated applicable PE staff costs as a ratio of CPSF transaction volume (kWh) managed to the total Power Enterprise transaction volume (kWh). The estimated first full year of CPSF sales volume as a percentage of the total sales volume that is currently managed by SFPUC was calculated and determined to be 20%. As was done in Approach 1, estimated hours for each staff member were calculated on a daily basis and using the Class Codes and billing rates for each staff member, the effective cost of the PE's services was determined. Using this approach, we estimated approximately $600,000 per year in fees would be paid to PE. . If the initial CPSF program size increases from the assumed 20-30 MW, then the level of compensation would increase as more PE staff time would likely be allocated to CPSF activities. Determining the potential incremental increase in initial program size was beyond the scope of this report but is

[24] From August 13, 2013 SFPUC Finance Proposed Not-to-Exceed Rates presentation, page 3. Procurement cost in the first full year of the CPSF program was given as $22,280,000 and had an Average Rate of $0.0807/kWh. This implies a volume of 2,760,263 kWh ($22,280,000/$0.0807/kWH).

identified as a key action item for SFPUC PE and CPSF to examine when the program moves forward.

In this approach we looked at the estimated first full year of CPSF sales volume as a percentage of the total sales volume that is currently managed by SFPUC. In 2013, SFPUC managed 1,351,148 MWhs of power sales and banking under the PG&E IA[25]. The total cost of the SFPUC PE staff referenced in Figure 3 can represented in by setting the "CPSF Allocation" percentage shown in Figure 4 to 100% (full cost), which results in an annual total cost of $2,969,396. The forecast CPSF sales volume in the first full year is 2,760,263. The ratio of the CPSF sales volume to the total PE 2013 sales volume is 20%. Under this approach we assume 20% of the total cost of the PE FTE staff that is performing procurement and portfolio management work for CPSF is allocated, which is $606,745 (20% of $2,969,396). Spreading that allocated cost over the forecast first full year of CPSF volumes results in a rate of $0.0220/kWh.

These calculations are summarized in the table below.

Class Code	Position Title	Role	CPSF Allocation		Annual Cost	"Hours per Day"
0933	Manager V	Electric Wholesale and Retail Services (strategic/management)	100%	$	314,097	8
0931	Manager III	Purchasing and Scheduling (oversee daily operations)	100%	$	271,297	8
5602	Utility Specialist	Purchasing and Scheduling (scheduling)	100%	$	251,203	8
5602	Utility Specialist	Purchasing and Scheduling (purchasing)	100%	$	251,203	8
0931	Manager III	Energy Trading Risk management and Settlements (risk management/settlements)	100%	$	271,297	8
5602	Utility Specialist	Energy Trading, Risk Management and Settlements (forecasting/risk management/settlements)	100%	$	251,203	8
5602	Utility Specialist	Retail Services (meter data management/ISO data submission)	100%	$	251,203	8
0931	Manager III	Energy Data Systems Manager (reconfiguration/integration changes needed for implementation)	100%	$	271,297	8
0931	Manager III	Reg/Leg affairs (regulatory compliance)	100%	$	271,297	8
5603	Utility Specialist	Specialist, Reg/Leg Affairs (RPS compliance)	100%	$	251,203	8
0933	Manager V	CCA Director (coordinate re program design/goals/load projections)	100%	$	314,097	8.0
11	**FTE Positions**		**Annual Total:**	**$**	**2,969,396**	

2013 SFPUC Power Sales:		**1,351,148,000**	kWh
CPSF Year 2 Sales:		**276,084,263**	kWh
Ratio of CPSF Year 2 Sales to 2013 SFPUC Power Sales:		**20%**	
Power Enterprise Staff Cost to Allocate:	**$**	**606,746**	
Effective Cost for Power Enterprise Procurement & Portfolio Management Services (Ratio x PE Total Annual Cost):	**$**	**0.00220**	$/kWh

Figure 5: Allocation of Power Enterprise FTE to CPSF Activities by Sales Volume[23]

- *Approach 3 Compensation Methodology*

Approach 3 used a set fee per unit of electricity served to calculate the avoided costs of services provided by the PE staff. An assumption of "avoided cost" is a reasonable approximation for the value provided. For example, while difficult to get accurate price transparency for these types of services, a high-level estimate of a typical service premium of $0.0020/kWh to $0.004/kWh would be reasonable. Our Approach 3 uses this range of premium and for the first full year of CPSF program forecast sales volume which could represent roughly $500,000 to $1,100,000 per

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[25] From SFPUC Comprehensive Annual Financial Report, FY2012-13, Page 272.

year in “service fees” flowing to PE for providing this critical work. If the initial CPSF program size increases from the assumed 20-30 MW, then the level of compensation would increase as more PE staff time would likely be allocated to CPSF activities. Determining the potential incremental increase in initial program size was beyond the scope of this report but is identified as a key action item for SFPUC PE and CPSF to examine when the program moves forward.

This avoided cost approach is typically used when accurate or reliable information about the underlying real cost is unavailable.

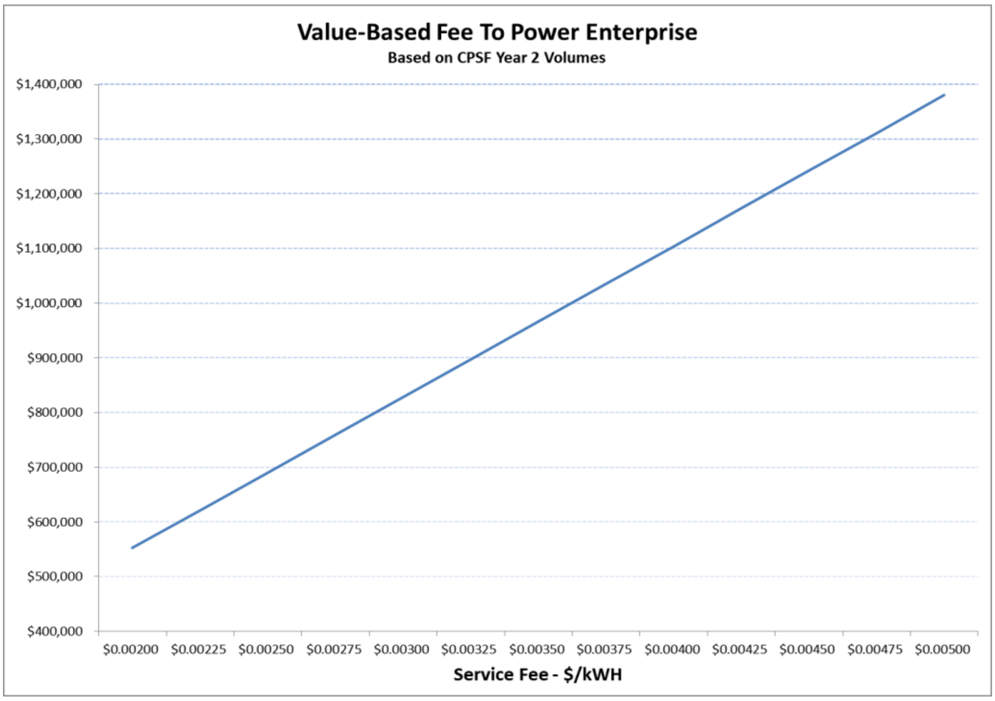

Figure 6: Range of Value-Based Fees

Other Costing Considerations

More critical is PE’s ability to assemble a portfolio of supply options that can create reasonable price certainty for CPSF, for a time horizon of at least 12-18 months. The opt-out feature of California CCA programs might pose a portfolio forming risk for other areas. However, based on the experience of the Marin and Sonoma CCA programs, as well as initial marketing research indicating high customer acceptance of the CPSF, the CPSF program may experience fairly low rates of opt out. Thus, the CPSF program should have little trouble acquiring the initial set of customers for the initial roll-out of 20-30 MWs and can then incrementally add customers, perhaps in 100 MW size increments up to the total forecast CPSF program demand of 400 to 600 MWs.

Flexibility in procuring shorter term supply contracts will facilitate price setting that supports the CPSF customer rate, yet does not create a longer term purchase obligation. Again, a transfer price or MOU mechanism would have to be put in place in which PE would commit to a transfer price[26] to CPSF within certain constraints. An agreement on the treatment of any charges to be passed through e.g. distribution losses, congestion, ancillary services, etc. would have to be defined and agreed upon. In addition, an appropriate "risk premium" cost component would need to be set in order to allow PE or CPSF to build a reserve fund over time which would then be used to cover situations where energy costs might temporarily exceed the agreed-to transfer price.

1.1.2 Subtask B: Assess Staffing Needs

Current Capacity

In our May 5th meeting with PE Staff, we discussed the roles and functions that were needed to support the proposed CPSF program. Comments from Staff were incorporated into Subtask A above, and assumed that a third party would provide back office services (e.g. Noble Americas Energy Solutions) including Meter Data Management Agent (MDMA) services for the CPSF customers.

We then discussed the incremental level of effort that might be required by Staff to manage procurement and portfolio management for CPSF. Staff expressed the opinion that, for the initial CPSF program implementation of 20-30 MW, there would be no material staffing impact to the current PE organization. There are currently three and soon will be four PE staff members that perform trading and scheduling functions, and those personnel would be capable of integrating servicing the CPSF supply within their current workload. There are currently 11 FTE positions in PE that would provide some level of service to CPSF procurement and portfolio management. Staff did mention that there is a plan to add 0.5 Full Time Equivalent (FTE) to support back office integration with the third party service provider (e.g. Noble Americas Energy Solutions), but that would also be the case under the scenario of having a third party provide procurement and portfolio management services. PE plans to continue to use the services of a third party for Scheduling Coordination and are examining the alternative of using a such a third party as a Scheduling Agent with PE being the actual Scheduling Coordinator of record. Continued use of either a third party Scheduling Coordinator or a Scheduling Agent is being considered so that PE does not need to staff a 24x7 Real Time desk. PE Staff believes, and we agree, that the current and near term level of transactions do not warrant establishing a Real Time desk.

Future Staffing Needs

In the longer view, Staff expressed the opinion that an additional incremental retail load of approximately 100 MW would likely require some incremental staff, particularly in the

[26] The term "transfer price" is used in this report to represent a range of pricing scenarios available to SFPUC, including a fixed price or an "at cost" pass through to CPSF. The main issue is that an agreement between SFPUC/PE and CPSF will need to be designed and agreed-to, then continuously monitored as the CPSF program becomes operational.

forecasting, scheduling and trading roles. Staff estimated that about 2-3 FTEs would be required and we concur with that estimate. More exact staffing needs can be determined once the scope of PE services is finalized and the CPSF is given approval to move forward. The incremental 100 MW could consist of either CPSF load or incremental retail customer load acquired through PE's planned marketing effort to in-City commercial and industrial customers. CPSF would expect to pay for some portion of the incremental resource. Although it is somewhat premature to estimate staffing changes required beyond the initial 100 MW increment, it is likely that additional staff will be needed incrementally and a reasonable estimate of addition staff would be 1-3 staff members for each 100 MW increment of additional load. The "transfer price" methodology that is ultimately developed (whether one of the 3 methodologies presented above or a variation) would produce appropriate revenue flowing to SFPUC PE to fully cover the cost of incremental resources added in support of expanding the CPSF program.

As the program grows, experience will be gained and expertise grown within the PE organization. That being said, a more diverse portfolio of energy supply products needed to support growing CPSF load as well as the anticipated growth of in-City retail load may require a higher level of retail load forecasting, integrated resource planning, supply portfolio optimization skills; and perhaps, at some point, more advanced deal structuring expertise to identify and capture supply products that most cost effectively meet the needs of the PE portfolio. Moreover, as transaction volume and complexity increases (again, due to CPSF growth in conjunction with in-City retail load growth) more advanced risk measurement, metrics and reporting may need to be developed and perhaps require more risk management expertise than existing Staff may currently have available.

1.1.3 Subtask C: Potential Benefits, Economies or Efficiencies

In our opinion, at the highest level the CPSF program is a natural extension of the existing SFPUC PE function. The CPSF is designed to be a self-supporting program and must operate as such. Because the skills, expertise, processes and systems needed to manage the procurement and portfolio management services for CPSF are essentially the same as those already in use and being developed within SFPUC PE, potential benefits and economies of scale may result from PE's direct support of the CPSF. Although certain aspects of the CPSF program (i.e. marketing, customer care, resource build-out, etc.) must be managed separately, CPSF's supply procurement and portfolio management functions can be integrated cost-effectively.

Further analysis is needed to determine if additional staff needed is proportional to the total load, or to total number of customers or is proportional to some other factor.

Assess Power Portfolio, Forecasting and Risk Management

An integrated strategy is an essential aspect of successful portfolio management. A diverse portfolio (of supply and load) is more cost and risk effective. Larger loads facilitate better financial transactions in the wholesale market and those benefits flow to the overall portfolio cost. A portfolio with a cost effective generation hedge used in conjunction with a range of short-term and long-term market transactions has the potential to be more predictable and stable over time. A diverse portfolio is thus able to take advantage of changes in the marketplace and will generally represent a lower overall risk. Aggregated retail load (shaped load) is more efficiently and effectively managed as opposed to multiple smaller individual portfolios.

Forecasting, scheduling, settlement, risk management and reporting system needs for CPSF and PE's existing customers are essentially identical and thus efficiencies and economies of scale are gained by using these same processes and resources for both CPSF and PE customer base.

SFPUC PE Compensation from CPSF

Financially, because CPSF is designed to be self-supporting, rates can and should be set to include appropriate cost and value based compensation to PE for services and products provided. There are multiple ways of determining the compensation amount including the number of hours Staff spends on CPSF tasks, or metrics based on the amount of energy consumed. The determination of the compensation cost for services provided by PE should be based on the amount of energy used by CPSF customers because doing so will scale the compensation to the effort required. The amount of effort required to support CPSF is expected to grow as the customer base increases over time. Potential metrics to be used to determine the compensation include peak load and total energy consumed monthly. Peak load is typically measured in MWs per time period which may be either monthly or annually. Total energy used is typically measured in megawatt hours (MWhs) per month.

If these services are obtained from a third party, those dollars are flowing out of the SFPUC as opposed to flowing into PE for services they are already capable of providing. Moreover, as the CPSF program evolves, and as PE likely develops credit capacity to support increased transaction volume in the wholesale market post PG&E IA expiration, CPSF would also be positioned to support the credit capability of PE through a proven successful CPSF program. As local build-out proceeds, credit collateral requirements from PE and the market may be reduced.

1.2 Third Party Power Procurement Evaluation

Operationally, CPSF will be responsible for:

1. Procuring and providing electric power needs for constituent customers;
2. Electric power Resource Adequacy and reserve requirements;
3. Electric power scheduling and related financial settlement with the CAISO; and
4. Customer Care Services

To successfully initiate the program CPSF has envisioned, the CCA will require the services of an experienced power market participant to manage the short and long term power products portfolio and provide the daily operational functions necessary to schedule, balance and financially settle the power and ancillary services required to serve CPSF's customer load. These functions may be obtained either from one provider or from discrete providers of the specific services. For example, CPSF could procure CAISO Schedule Coordination services from a 3rd party (e.g. APX, TEA) and procure power products from the market through solicitations and setting up trading agreements with qualified market participants for transacting (purchase and sale) of energy products on a daily and intra-day basis. While this approach is technically possible, it would be cost and time prohibited when compared to obtaining all the needed services from SFPUC PE. SFPUC PE may then outsource certain functions such as CAISO Schedule Coordination services.

SFPUC and CPSF will need to determine which elements of the CPSF operations can and will be staffed and managed by CPSF and PE staff and which elements are candidates for potential outsourcing to other entities.

In meetings with PE Staff in May and July 2014, it was stated that current PE staff could support forecasting, procuring and managing energy supply products[27] necessary to support CPSF's forecast initial 20-30 MW load. Existing PE processes, procedures and systems would be used by PE when administering CPSF load and the incremental CPSF load would be aggregated into PE's daily portfolio position.

PE would establish a separate CAISO Scheduling Coordinator Identification (SCID) for CAISO accounting and settlement which would be used to pass through appropriate market costs to CPSF. Creating separate SCIDs is both simple and feasible. PE would manage the CPSF load obligation as part of the existing and future SFPUC load obligation, but would administratively separate those obligations (e.g. RAR) and track obligation fulfillment for both SFPUC and CPSF. CAISO and CPUC regulatory obligations for CPSF should be administered separately to allow applicable costs to be passed to CPSF even for cases when the same function is used by both CPSF and PE (for example when Hetch Hetchy capacity is used to satisfy some CPSF RAR requirements).

SFPUC PE will likely continue to outsource the CAISO Schedule Coordinator responsibility for SFPUC's existing load as well as the CPSF load. Thus CPSF will benefit from SFPUC PE's existing, and anticipated continued, use of a 3rd party CAISO Schedule Coordinator (SC).

There is no material value or advantage for CPSF to contract for the types of energy procurement and portfolio management services needed to support CPSF's initial 20-30 MW load because those services can be more effectively and efficiently provided by SFPUC PE's existing organization. Contracting with a third party would duplicate existing skills, processes, procedures and systems currently available within SFPUC PE. Moreover, PE has stated that they have the capacity and the necessary skill sets to provide these services and after evaluation EnerNex confirms that this is the case. PE will use its existing processes, procedures, systems and staffing, including leveraging existing contract services such as the APX contract for CAISO scheduling coordination to fully meet the needs of CPSF's planned initial customer load. SFPUC may use existing or new 3rd party power market entities for soliciting or transacting for power

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[27] "Energy Supply Products" include energy, capacity (System and Local Resource Adequacy), ancillary services, transmission congestion management (including CRRs), etc.)

products that would be used to meet CPSF load just as they may do currently for managing their existing supply portfolio. The CPSF incremental load has essentially no material impact to PE's current workload or portfolio mix.

Given SFPUC PE's current role and responsibility, it would be a natural extension of that role to provide power procurement services to CPSF.

1.2.1 Power Procurement

We believe there are benefits in economy, efficiency and scale by having SFPUC PE manage the CPSF supply portfolio. CPSF would rely on SFPUC PE to provide all necessary Schedule Coordination, forecasting and procurement activities to meet CPSF's load obligations including energy, capacity, ancillary services, balancing energy, and resource adequacy. Given that SFPUC PE is in the market procuring power for SFPUC's customer load when HH supplies are inadequate, the incremental addition of the initial CPSF load of 20-30 MW has no material impact on SFPUC's operation or staffing.

The initial CPSF load of 20-30 MW is on the fringes of the size that it is worth a third party's time to manage. SENA had stated that 20 MW was the smallest load it would consider for offering power procurement and SC services. The premium to be paid to a third party provider to provide services and some level of price risk is potentially unaffordable to CPSF in terms of offering a competitive rate to its customers. Negotiation of the SENA contract demonstrated that price risk mitigation is expensive and potentially cost prohibitive. Moreover, a third party provider would, by practice and necessity, require a commitment from CPSF to procure – at a minimum – a specified amount of energy and capacity for a specific term. It is therefore recommended that CPSF continue considering 20-30 MW of load for the first phase of CCA implementation based primarily on the fact that SFPUC PE can easily incorporate that size load into its operation without requiring incremental resources[28]. As previously mentioned, the estimate of 20-30 MW of customer load in the initial phase of the CPSF program was largely based on the initial power supply contracting strategy and the cost impact of credit security required by Shell Energy North America (SENA). The "resetting" of the program which includes having SFPUC PE manage the CPSF supply portfolio may introduce the opportunity to increase the initial program size, within constraints of doing so using only existing capability and capacity of SFPUC PE staff and operations. Determination of the potential incremental increase in initial program size that can be accommodated by existing PE staff is beyond the scope of this report but is identified as a key action item for SFPUC PE and CPSF to examine when the program moves forward.

As we have seen in other CCA procurements, power purchase agreements like the one considered from SENA are most often a shaped power product which specifies a fixed load (MW) for each hour of each day over the term[29] of the contract. To the extent the actual load is

[28] SFPUC staff made this determination during interviews in May 2014 as part of the initial assessment work.

[29] Contract terms are usually a minimum of 1 year, and typically 3 year commitments.

different (either more or less) than the contracted load shape, CPSF would be responsible for incremental purchases and/or sales of energy in the CAISO Day Ahead (DA) and/or Real Time (RT) markets. By utilizing the existing skills, processes, procedures and systems available from SFPUC PE to manage CPSF's power product portfolio, CPSF could benefit from SFPUC PE's use of an aggregated portfolio to minimize long-term fixed price and volume commitments while still receiving reasonable supply price certainty in the underlying transfer price. In addition, to the extent SFPUC PE has surplus Hetch Hetchy power available, CPSF would be well positioned to take advantage of that surplus and potentially lower the underlying effective cost of the CPSF supply. The MOU/Transfer Price would develop and define the requirements for forecasting CPSF loads and the settlement process to be used.

There are no material advantages to having a third party provide power procurement services to CPSF if SFPUC PE can provide these same services. All indications from SFPUC PE are that they are more than capable of cost effectively doing so and EnerNex agrees with SFPUC PE's assessment.

1.2.2 Resource Adequacy

In order to ensure reliable grid operation, all California Load Serving Entities (LSEs), must provide reserve power capacity resources (Resource Adequacy Requirement or "RAR")[30] to ensure the safe and reliable operation of the grid in real time. Thus, LSEs (including CCAs) are required to procure a defined amount of reserve capacity and their Scheduling Coordinators must file forms with the CEC verifying that they meet the reserve requirements of the Resource Adequacy (RA) program.

Rules are provided for "counting" resources to meet resource adequacy obligations. The resources that are counted for RA purposes must make themselves available to the CAISO for the capacity for which they were counted. The RA process is not a static, unchanging set of procedures. Rather, it's an evolving program with new procedures. In particular, currently there is a new requirement for "flexible RA" to mitigate rapid changes in electricity demand per CPUC Decisions 13-06-024[31] and 14-06-050[32], which begins as a mandatory requirement for 2015.

To meet the current RA reporting requirements, CPSF must demonstrate that it meets the following reserve capacity requirements:

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[30] CPUC Resource Adequacy Information: http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/

[31] CPUC Decision 13-06-024 Adopting Local Procurement Obligations for 2014, a Flexible Capacity Framework, and Further Refining the Resource Adequacy Program, July 03 2013: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M070/K423/70423172.PDF

[32] D1406050 Adopting Local Procurement and Flexible Capacity Obligations for 2015, July 1, 2014: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M097/K619/97619935.PDF

1. Resource Adequacy Requirement (RAR) planning reserves are required to bring total capacity, including ISO required ancillary services, up to 115% of forecast load for summer months (May-September) and 100% of forecast load for all other months. Forecast load is based on a 1 in 2 (50%) probability year and baselined against the CEC forecast;
2. Local RAR considers a longer-term peak based on a 1 in 10 (10%) probability year analysis, and the loss of the two largest contingencies (generation or transmission). LSEs are required to demonstrate their ability to procure 100% of Local RAR (LRAR) requirements for summer months;
3. Demonstrate procurement of 90% of RAR and 100% of Local RAR one year ahead of time (due October 31 for the following year);
4. Demonstrate 100% of RAR two months ahead of time;
5. Beginning in 2015, CPSF must provide Flexible Resource Adequacy which CPUC Decision 13-06-024 defines as "Flexible capacity need" as the quantity of resources needed by the California ISO to manage grid reliability during the greatest three-hour continuous ramp in each month. CPSF would be required to contract for 90% of their monthly needs in the year-ahead time frame. CPSF would also need to secure adequate qualified flexible capacity to serve their peak load including a planning reserve margin in a month-ahead time frame through the year.
6. Provide load forecast updates to the CEC yearly in January and March.

The local energy resources discussed in this report will also count towards RAR when those resources are developed and operational. Behind the Meter generation serves to reduce the RAR while grid interconnected distributed generation[33] serves to help meet RAR. CPSF will need to procure qualified capacity sufficient to meet any remaining RAR obligations.

SFPUC PE is responsible for demonstrating to CAISO that they have the required qualified capacity to meet RAR requirements associated with their existing municipal load, thus SFPUC PE is already in the RAR market, as a buyer as well as a seller. CPSF may be able to leverage SFPUC PE's existing RAR resources as well as their market access to meet the RAR requirements associated with CPSF's load.

IF CPSF were to use a third party provider for RAR, they would, by practice and necessity, require a commitment from CPSF to procure – at a minimum – a specified amount of capacity for a specific term, similar to the commitments discussed regarding energy procurement. As with energy, the third party supplier would require a commitment from CPSF to a fixed monthly capacity value (MW) each month over the term of the contract. By utilizing the existing skills,

[33] Owners of grid connected distributed generation must apply to PG&E to qualify resource adequacy deliverability for these resources.

processes, procedures and systems available from SFPUC PE to manage CPSF's power product portfolio, CPSF could benefit from SFPUC PE's use of an aggregated portfolio to minimize long-term fixed price of required RAR through potentially leveraging SFPUC PE's existing resources that may be available for meeting RA requirements. The MOU/Transfer Price would develop and define the requirements for forecasting CPSF loads and the settlement process to be used for annual and monthly RA resources.

There are no material advantages to having a third party provide RA procurement services to CPSF if SFPUC PE can provide these same services. All indications from CPSF SFPUC PE are that they are more than capable of cost effectively doing so and EnerNex agrees with SFPUC PE's assessment.

1.2.3 CAISO Schedule Coordination

The CAISO requires a certified Scheduling Coordinator (SC) to participate in the California energy market, thus CPSF will require the services of a Scheduling Coordinator. The SC must both be specially trained in CAISO procedures and must have access to a secure communications link to the CAISO system through either the Internet or through the Energy Communications Network (ECN).

The CAISO SC manages bids in the CAISO ancillary service and energy markets. Pricing within the CAISO markets is determined by Locational Marginal Prices (LMP) which define the cost of delivery to specific locations based on the cost of generation, distance from generation resources and congestion of transmission to that location. Energy bids are made hourly in the day-ahead market. Real time balancing of supply and demand is achieved through the real time market including the Hour Ahead Scheduling Process (HASP) and ancillary services.

An SC Applicant is responsible for and must meet all CAISO SC certification requirements in order to receive SC certification. However, the certification requirements to complete real time and contact drills and the establishment of Settlement Quality Meter Data System (SQMDS) connectivity and functionality of other technical systems may be completed by the Scheduling Agent acting on behalf of the SC Applicant.

The SC itself, not the Scheduling Agent, is ultimately responsible for all CAISO market and administrative costs, scheduling, operating performance, and CAISO network security, as well as contractual and financial settlement issues consistent with its executed Scheduling Coordinator Application (SCA).

A person seeking SC certification must complete the CAISO certification steps summarized below:

1. CAISO Tariff[34] Section 4.5.1.1.4, Scheduling Coordinator Applicant Returns Application
2. CAISO Tariff Section 4.5.1.1.5, Notice of Receipt

[34] CAISO Regulatory Rules Tariff: http://www.caiso.com/rules/Pages/Regulatory/Default.aspx

3. CAISO Tariff Section 4.5.1.1.6, CAISO Review of Application
4. CAISO Tariff Section 4.5.1.1.7, Deficient Application
5. CAISO Tariff Section 4.5.1.1.7.1, Scheduling Coordinator Applicant's Additional Information
6. CAISO Tariff Section 4.5.1.1.7.2, No Response from Scheduling Coordinator Applicant
7. CAISO Tariff Section 4.5.1.1.8.2, Time for Processing Application
8. CAISO Tariff Section 4.5.1.1.9.1, Scheduling Coordinator Applicant's Acceptance
9. CAISO Tariff Section 4.5.1.1.11, Final Certification of Scheduling Coordinator Application
10. At least 120 days prior to the proposed start of service, the SC Applicant must submit a completed application form to the CAISO with a non-refundable application fee

The SC Applicant has twelve (12) months in which to complete and pass the requirements for certification. If certification is not completed within twelve (12) months from the initial submittal date, the CAISO can close the application upon the provision of thirty (30) days advance notice.

In order to participate in the CAISO energy markets on the CCA's behalf, the scheduling coordinator must complete the requirements summarized below.

Table 6 Scheduling Coordinator Requirements

Requirement
Establish Financial Security with CAISO and meet the Minimum Participation Requirements
Establish Network Interface 1. Internet 2. ECN – secure private network
Designate a Point of Contact
Request Application Access
Attend Training
Complete Market Proficiency Test
Test Fed-Wire - a computerized high-speed communication system linking the banks within the Federal Reserve System
Submit SC Emergency Plan - The SC emergency plan ensures that a procedure is in place that gives the SC the capability to submit, withdraw, or adjust Bids and Self-Schedules in the case of an emergency
Complete Real-Time and Contact Drills

Requirement
Establish CAISO Automated Dispatch System (ADS) Access
Establish SLIC System Access
Attend SLIC Training
Establish Access to Operation Meter Analysis and Reporting (OMAR)
Submit Acknowledgement Forms
Training & Testing - SCs are required to maintain continued proficiency and compliance with the rules and regulations concerning participation in the CAISO Markets

SFPUC PE will likely continue to use either a third party Scheduling Coordinator or a Scheduling Agent as PE does not need to staff a 24x7 Real Time desk.

CPSF will require Schedule Coordination services to service the initial and ongoing CPSF customer load. CPSF could become a certified SC or contract for SC services. At the initial stages of the CPSF program, it would not be cost effective or efficient for CPSF to build the processes and systems necessary to become a certified SC[35].

CPSF's procurement and scheduling needs can be met under this existing arrangement if PE works with its SC services provider to establish a CPSF Schedule Coordinator Identification (SCID). It is recommended that CPSF be established with a unique SCID to specifically account for CPSF market transactions separate from any existing SFPUC SCIDs.

1.2.4 Customer Care Services

Similar to the investigation into a preferred power procurement approach, CPSF will need to determine whether to contract with a third party for customer care services or to provide some or all of these services with internal staff. It is assumed that CPSF in collaboration with SFPUC Customer Service will be the primary provider for customer care services. CCA Customer Care Services include:

1) **Electronic Data Exchange Services**:

[35] SFPUC PE currently outsources its Scheduling Coordination services to APX, mainly due to cost and staffing efficiencies captured by doing so. Currently SFPUC PE does not have a load and resource management requirement that justifies establishing the required 24x7 staffing to support SC operations. Similarly, it would make no cost or operational sense for CPSF to pursue becoming a certified SC.

1. Exchange CCA Service Requests ("CCASRs") with PG&E to specify the changes to a CPSF customer's account status such as a rate class change or opening/closing of an account. (814 Electronic Data Interchange Files). Obtain customer usage data from PG&E's MDMA server (867 Electronic Data Interchange Files).
2. Obtain customer usage data from PG&E's MDMA server (867 Electronic Data Interchange Files).
3. Communicate the amount to be billed by PG&E for services provided by the CPSF (810 Electronic Data Interchange Files).
4. Receive payment transactions toward CPSF charges from PG&E after payment is received by PG&E from customers (820 Electronic Data interchange Files).

2) **Customer Information System (CIS)**:

- Maintain a customer database of all CPSF customers and identify each customer's enrollment status, payments, and collection status.
- Generate reports from the CIS to provide customer metrics.

3) **Customer Call Center**:

- Staff a call center with additional coverage available during customer enrollment periods.
- Receive calls from CPSF customers referred to CPSF Customer Care by PG&E
- Receive calls from CPSF customers choosing to contact CPSF Customer Care directly without referral from PG&E.
- Respond to telephone inquiries from CPSF customers using a script developed by CPSF Customer Care
- Customer care inquiries may be received through telephone calls, internet chat, or email.

4) **Billing Administration and Support**:

- Maintain a table of rate schedules, provided by the CPSF, and calculate bills.
- Apply PG&E meter data for usage against applicable CPSF rate for each customer.
- Review application of CPSF rates to PG&E accounts to ensure that the proper CPSF rates are applied to the respective accounts.
- Provide timely CPSF billing information to PG&E to meet PG&E's billing window.
- Remedy billing errors with customer and with PG&E.

5) **Reporting:** Customer Care service will be the source for performance and status reporting for the CPSF. The following are some, but not all, of the types of reports needed:

- Daily and monthly report of billing information (usage, amount, customer information, etc.).
- Daily and monthly report of payment transactions received.
- Weekly report of delinquent accounts.
- Weekly report of exceptions (usage delayed, usage received but unbilled, usage gaps, etc.) and actions/responsible party engaged to resolve with target date of resolution.
- Weekly report of accounts added and dropped.
- Monthly report of billing error rate.
- Monthly report of billing timeliness.
- Monthly report to the CPSF that indicates the number of Customer Call Center inquiries received, the average time required to respond to the inquiry and the percentage of issues resolved per inquiry.
- Other reports as may be specified by the CPSF.

6) **Settlement Quality Meter Data**: Customer Care would be responsible for providing the CPSF and its designated Scheduling Coordinator with Settlement Quality Meter Data (SQMD) as required by the CAISO.

CPSF should work with PUC Customer Service to determine which of these functions can or should be performed by PUC Customer Service. For example, while SFPUC has a call center that could be gradually expanded to support CPSF, SFPUC would need to add the capability for performing customer billing functions. Alternatively or initially, CPSF could provide Customer Care Services through the use of a qualified service provider. This approach has proven cost effective and successful in other CCA implementations[36]. While outsourcing Customer Care Services makes economic and efficient sense during the initial phase of CPSF, doing so does not preclude pulling this function back into the SFPUC sometime in the future. The existing SFPUC Customer Service group may be a viable option for CPSF Customer Care Services, as well as providing services to SFPUC's growing retail customer base.

1.3 Develop Plan for Procurement Services

Meetings with PE staff confirmed that procurement services for the initial 20-30 MW of CPSF load would simply leverage the existing forecasting, planning, market assessment and procurement processes that CPUC/PE currently uses to serve existing municipal load. PE would

[36] Marin Energy Authority and Sonoma Clean Power have contracted with a third party provider of Customer Care Services. These providers have successfully integrated required processes and systems with the local utilities as well as data exchange with the respective Scheduling Coordinators. The City of Lancaster CA's Choice Energy CCA is pursuing the same approach for providing Customer Care Services.

work with CPSF staff to develop a mutually agreed-to procurement plan that best matched CPSF's forecasted load and price point and incorporated market information that PE would normally have access to.

Prior to procuring energy, it will be necessary to determine the power cost parameter ranges that can feasibly support the green renewable energy plan offerings. For both the 100% renewable energy and the Light Green plan, the generation price points needs to be determined so that the energy procured is not too costly for the envisioned rate structure. Further, the maximum average energy price needs to be determined so that the City's goal of affordable renewable energy can be balanced with the City's goals for local power generation, leadership in renewable energy and local job creation.

Determination of the maximum average renewable energy cost will allow the City to maximize local energy generation and local job creation while providing affordable renewable energy to the City's businesses and residents. The recommended method to accomplish all the City's goals is to first calculate the maximum wholesale energy price considering all CPSF's fiscal responsibilities (see Section 2), and then purchase the maximum amount of in-City and regional energy, balanced with less expensive non-regional energy which allows CPSF to sell energy at a rate competitive with PG&E. Once the price profile is developed for the CPSF portfolio which takes into consideration target retail electric supply rates, indicative market prices for various energy products, renewable generation costs (including REC's as required) and other energy portfolio costs (e.g. ancillary services, CAISO charges, Resource Adequacy, etc.), PE would work with CPSF to build a procurement plan that would identify the type, volume, price target and timing for acquisition of needed energy products and services.

For some types of energy products, PE would use a Request for Offers (RFO) process that is a common vehicle in the power markets for soliciting specific power products and services. PE would solicit RFOs from their existing qualified counter parties and the results obtained would be reviewed with CPSF to assure that market products and buy commitments were consistent with the portfolio price profile and the forecast CPSF revenue and rate levels. PE would utilize existing DA and HA CAISO market transactions to shape the CPSF supply to match load.

CPSF will need to work periodically with PE to develop and agree to a working set of procurement scenarios that PE can execute against to build the CPSF supply portfolio including energy, capacity and ancillary services. The procurement scenario and strategy process is most effectively done on an annual basis with quarterly reviews and adjustment discussions. Monthly updates on strategy execution are recommended. The strategy sessions would include market reports, forecasted prices; go to market strategies and transaction execution timing. The procurement process will need to be agreed to by CPSF and SFPUC. A Memorandum of Understanding (MOU) should be developed between CPSF and SFPUC PE that defines both parties' roles and responsibilities.

PE would use their existing Scheduling Coordinator (SC) for servicing CPSF load, and would establish a separate CAISO Schedule Coordinator ID (SCID). A separate SCID would keep CPSF delivery and settlement data separate from existing and future SFPUC customers and would ensure that all related CAISO charges flow to CPSF for settlement and that charges would be captured in CPSF rates.

There is no need to pursue either resurrection of the SENA contract or any contract from the market with similar provisions. Instead, CPSF should go back to market – through SFPUC PE - to multiple suppliers to seek specific products and services based on the portfolio strategy developed between SFPUC PE and CPSF. SENA may be one of the potential suppliers. The work that went into developing the EEI MSA can be leveraged to other suppliers in addition to SENA.

Changes to the current Risk Management and Trading policies and procedure documents will likely be required to facilitate SFPUC PE potentially making energy purchase commitments on behalf of CPSF that may exceed the current risk program limits. PE and CPSF will need to collaborate on market purchase strategy needs and determine what, if anything needs to be modified in the risk management policy, limits, controls and procedures. In a meeting with PUC PE staff in July, we reviewed the initial findings for Task 1, Subtasks A, B and C. Regarding the MOU, PE Staff indicated, and CPSF Staff agreed that CPSF will essentially be taking power products from PE on a "pass-through" cost basis. Risk management for market price and volume volatility will take place on the CPSF side of the ledger through a premium embedded in retail rates and a "fund" established in the CPSF ledger for reserves. After discussion and evaluation, EnerNex agrees that this approach can work if the necessary processes, procedures and agreement decisions are defined and put in place via an MOU to capture the portfolio planning, forecasting, and market purchase strategy discussed above.

CPSF would work closely with SFPUC PE to determine which energy products and services are needed and what the most optimal approach and timing are e.g. RFP, RFO, or direct market purchase. SFPUC would provide the products and services at a “portfolio cost” to be fully defined and agreed to in the MOU. CPSF would provide the price risk management hedging function, most likely through a reserve fund creation, on the CPSF accounts side of the ledger. The “pass-through” cost basis approach establishes an auditable accounts environment and provides defendable transparency for setting CPSF rates.

1.4 Task 1 Conclusions: Develop Plan for Procurement Services

1.4.1 SFPUC Power Procurement Evaluation

1) The option of SFPUC PE providing procurement and portfolio management services directly in support of CPSF is consistent with and complimentary to PE’s current and future functions and roles. Providing these services leverages existing expertise, skills, processes and systems. PE should be compensated for services provided using a payment methodology that best represents the underlying cost and the value of providing these critical services.
2) For the initial 20-30MW program, Staff comments indicated that they believe no new expertise would be required as the work anticipated is very consistent with the tasks that they are already managing. An incremental retail load of approximately 100 MW

would likely require some incremental staff, particularly in the forecasting, scheduling and trading roles. Staff estimated that 2-3 Full Time Equivalents (FTEs) would be required and we concur with that estimate. As previously mentioned, the initial CPSF size of 20-30 MW may be able to be increased without having to add incremental SFPUC PE staff. Determining the potential incremental increase in initial program size was beyond the scope of this report but we recommend that analysis as a key action item for SFPUC PE and CPSF to examine when the program moves forward.

3) We believe there are benefits in economy, efficiency and scale by having SFPUC manage the CPSF supply portfolio. Economies of scale may result in fewer staff being required for later increments of increased load. Additional customers will likely present more diversity in load usage which would lower costs and reduce risk.
4) Identification of the potential of this approach will be developed in Section 1.2. Utilizing SFPUC PE for forecasting and purchasing power for CPSF could utilize a transfer price, MOU or some other mechanism to provide appropriate compensation for services rendered. CPSF would most certainly have to compensate a third party for these services and that compensation is most commonly embedded in the price charged. An assumption of “avoided cost” is a reasonable approximation for calculating the value provided. Use of a fixed allocation of PE staffing resource time is another approach with an annual adjustment as the CPSF program grows. CPSF and SFPUC PE staff indicated that the fixed allocation approach is preferable for the initial CPSF program.
5) Although it is somewhat premature to estimate staffing changes required beyond the initial 100 MW increment, a reasonable estimate of the addition staff required would be 1-3 staff members for each 100 MW increment of additional load.
6) SFPUC PE and CPSF will need to develop a detailed MOU and/or transfer price agreement that documents, in a detailed manner (including settlement and dispute processes) how costs will transfer between the organizations and support cost/price transparency within CPSF.

1.4.2 Third Party Power Procurement Evaluation

1) We believe there are benefits in economy, efficiency and scale by having SFPUC PE manage the CPSF supply portfolio. CPSF would rely on SFPUC PE to provide all necessary Schedule Coordination, forecasting and procurement activities to meet CPSF’s load obligations including energy, capacity, ancillary services, balancing energy, and resource adequacy. Given that SFPUC PE is in the market procuring power for SFPUC’s customer load when HH supplies are inadequate, the incremental addition of the initial CPSF load of 20-30 mw has no material impact on SFPUC’s operation or staffing.

2) As previously mentioned, the estimate of 20-30 MW of customer load in the initial phase of the CPSF program was largely based on the initial power supply contracting strategy and the cost impact of credit security required by Shell Energy North America (SENA). Our continued reference to the initial CPSF program size of 20-30 MW of load for the first phase of CCA implementation was based primarily on the fact that SFPUC PE can easily incorporate that size load into its operation without requiring incremental resources[37]. The "resetting" of the program which includes having SFPUC PE manage the CPSF supply portfolio may introduce the opportunity to increase the initial program size, within constraints of doing so using only existing capability and capacity of SFPUC PE staff and operations. Determination of the potential incremental increase in initial program size that can be accommodated by existing PE staff is beyond the scope of this report but is identified as a key action item for SFPUC PE and CPSF to examine when the program moves forward.
3) CPSF is planning to provide Customer Care Services through the use of a qualified service provider. This approach as proven cost effective and successful in other CCA implementations. While outsourcing Customer Care Services makes economic and efficient sense during the initial phase of CPSF, doing so does not preclude pulling some or all of these functions back into the SFPUC sometime in the future. The existing SFPUC Customer Service group may be a viable option for CPSF Customer Care Services, as well as providing services to SFPUC's growing retail customer base. SFPUC Customer Service currently has a Call Center, but would need to add the capacity to perform customer billing.

1.4.3 Develop Plan for Procurement Services

1) There is no need to pursue either resurrection of the SENA contract. Instead, CPSF should go back to market – through SFPUC PE - to multiple suppliers to seek specific products and services based on the portfolio strategy developed between SFPUC and CPSF.
2) CPSF will need to work periodically with PE to develop and agree to a working set of procurement scenarios that PE can execute against to build the CPSF supply portfolio including energy, capacity, ancillary services and resource adequacy
3) SFPUC PE would work with CPSF staff to develop a mutually agreed-to procurement plan that best matched CPSF's forecasted load and incorporated market information that PE

[37] SFPUC staff made this determination during interviews in May 2014 as part of the initial assessment work.

would normally have access to. For some types of energy products, PE would use a Request for Offers (RFO) process that is a common vehicle in the power markets for soliciting specific power products and services. PE would solicit RFOs from their existing qualified counter parties and the results obtained would be reviewed with CPSF to assure that market products and buy commitments were consistent with forecast CPSF revenue and rate levels.

4) SFPUC PE would use their existing Scheduling Coordinator (SC) for servicing CPSF load, and would establish a separate CAISO Schedule Coordinator ID (SCID). A separate SCID would keep CPSF delivery and settlement data separate from existing and future SFPUC customers and would ensure that all related CAISO charges flow to CPSF for settlement and that charges would be captured in CPSF rates.
5) Changes to the current Risk Management and Trading policies and procedure documents will likely be required to facilitate SFPUC PE potentially making energy purchase commitments on behalf of CPSF that may exceed the current risk program limits. PE and CPSF will need to collaborate on market purchase strategy needs and determine what, if anything needs to be modified in the risk management policy, limits, controls and procedures.

2 TASK 2: TIMING/ECONOMIC BENEFITS OF LOCAL BUILD-OUT

2.1 Local Build-out Objectives

2.1.1 Achieving Local Build-Out Objectives

Economic benefits from the construction and operation of projects will come from three primary sources:

- First, San Francisco will see benefits from the employment of local residents, and spending by those residents;
- Second, San Francisco will see benefits from purchasing by firms employed to install and operate projects.
- Third, there can be an economic impact from shifts in spending on energy.

For the first two benefits, San Francisco will benefit solely from employment and expenditures that occur with the City and County. For the third benefit, an increase (or decrease) in energy spending by customers in San Francisco will result in a decrease (or increase) in their spending on other goods and services, including goods and services in San Francisco. However, with local control and generation, the shift in spending on energy stays within San Francisco. For example, if spending shifts from a power producer in Southern California to a power producer within the City and County of San Francisco, the net economic impact to the City can increase even if the total spent on energy also increases, because the recipient of the revenues is within the City and will spend part of those revenues on goods and services in the City. However, it is worth noting that under most financing scenarios for financing the start-up of CPSF and build-out of local resources, a significant portion of revenue will be used to pay for debt or equity return, and therefore would not have significant economic benefit during the financing period.

To maximize local economic benefits, the City should focus on local employment and procurement provisions, and establish a preference for projects that are physically located within the City and County of San Francisco.[38] For these reasons, maximizing local benefits will require measures to encourage or require local economic activity. Encouragement could come from a measure such as adding a weighting factor for local procurement or employment, or the physical location of a project. Requirements for local benefits can come from the imposition of local contracting, procurement and hiring requirements, and from a preference for transaction structures (such as PPAs and PPPs) that provide for the eventual ownership of generation facilities by local entities.

Local requirements will likely result in higher prices in some cases, however, and policy makers will have to assess the tradeoff between local economic benefits and increased costs.

2.1.2 Economic Benefits

A detailed analysis of the direct, indirect and induced economic impacts of implementation of the program[39] would include, but not be limited to, the employment and expenditures related to installation, any cost savings that will be in turn be spent in the local economy, and any expenditures on electricity shifted from remote sources to local sources. For example, the analysis would include the local employment and expenditures related to installation, as well as the impacts of shifts in expenditures, such as from payments to remote power producers to payments to local power producers.[40] The analysis would be structured to allow comparison of alternatives, as appropriate. For this report, we have attempted to address the key points of a detailed analysis with a more qualitative high level approach utilizing the data available and have

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[38] The City has a local hiring requirement for City contracts, but Willdan is unsure how these requirements apply to PPAs and PPPs. For projects more than 70 miles from San Francisco, the requirement is to utilize workers local to San Francisco or to the area or region of the project. There is also an exemption for "specialized trades" which may apply to certain types of projects.

[39] Direct impacts are the changes in economic activity that arise directly from expenditures and changes in labor income. Indirect impacts are economic activity generated by industry-industry transactions to support the economic activity (such as purchase of construction supplies and materials. Induced impacts are the economic effects of spending by employees in affected industries.

[40] In 2012 the City's Office of Economic Analysis prepared and estimate of the economic impacts of a proposed contract with Shell Energy for CleanPowerSF. This analysis evaluated only the impact of the increased cost of renewable energy and therefore showed a negative economic impact.

reviewed the types of economic activities involved with both implementation and operation of the plan.

Following are the expected types of economic impacts that will be generated by projects included in the program:

- **Local Employment:** The employment of those implementing the program, including City staff, private sector managers, installers, etc., will generate direct, indirect and induced economic impacts in the economy of San Francisco.
- **Implementation Spending:** The expenditures on materials for implementation may have a positive economic impact in the City, depending on the source of those materials.[41]
- **Energy Expenditures:** The prior study[42] found a negative economic impact from the increase in energy expenditures for renewable power, which went to recipients outside the City. This reduced expenditures for other goods and services as residents reduced their expenditures to make additional payments for power. For the contemplated program the net economic impact may be negative or positive, depending on a number of factors. As before, increased expenditures outside the City will reduce economic activity within the City. Shifts to local energy producers will have a positive effect, except to the extent that the shift is accompanied by higher expenditures than would otherwise be the case. In that circumstance the exact economic impact would need to be analyzed to determine whether it is a net negative or positive[43].

Using the National Renewable Energy Laboratory (NREL) Jobs and Economic Development Impact Models (JEDI) tool to create a rough estimate of the types of economic impacts the City can expect to see from each $1 million in project costs expended. For the following tables Willdan has not included the employment of City or PUC staff, as these are common to all of the projects and do not appear to be a significant factor in distinguishing among them. It is important to note, however, that these impact estimates are based on very general prototypes and therefore should be used only as a general guide. Additional analysis should be conducted to inform the decision making process once more detailed project information is available. On an operational basis there is a potential economic impact from a shift in spending on electricity. If

[41] For example, materials manufactured in China and brought to San Francisco will not have an economic impact, but items purchased from local suppliers will have an impact from the retail activity and, potentially, manufacturing or assembly.

[42] Overview presentation provided by City's Office of Economic Analysis dated May 12th, 2012

[43] The economic impact analysis prepared in this report does not examine any shifts in consumer expenditures on electricity.

electricity rates go up consumers shift their spending from other goods and services, which can have a negative effect on economic output. If the generating facility is within the City of SF or owned by the City, however, this effect can be offset) by the increase in revenue.

Table 7 Construction Benefits

SF	4.9	Yes	Possible with local procurement req.	Positive
Regional	5.1	Minor	Regional	Regional
California	6.4	None Significant	None Significant	None Significant
Outside CA	Varies	None	None	None

[44] Local is defined to be within 70 miles of the City to be consistent with the City's Local Hiring Ordinance, Mandatory Local Hiring Ordinance Fact Sheet, bulleted item on top of page 2, http://www.workforcedevelopmentsf.org/aboutus/images/stories/AboutUs/ForTrainingProviders/Local_Hire/local%20hiring%20ordinance%20fact%20sheet.pdf

The location of labor is driven by the frame of reference of the analysis. This estimation has been broken down based on assumptions regarding the location of expenditures.

SF	6.3	Yes	Possible with local procurement req.	Positive
Regional	6.7	Minor	Regional	Regional
California	6.9	None Significant	None Significant	None Significant
Outside CA	Varies	None	None	None
SF	2.7	Yes	Possible with local procurement req.	Positive
Regional	2.7	Minor	Regional	Regional
CA	6.3	None Significant	None Significant	None Significant
Outside CA	Varies	None	None	None
California	2.3	Depends on location	Possible with local procurement req.	Locational
Outside CA	None	None Significant	None Significant	None Significant
SF	6.6	Yes	Possible with local procurement req.	Positive

[45] Estimates based on residential photovoltaic installation as a proxy for other BTM project types

Table 8 Post-construction Operations Benefits

SF	0.05	Yes	Negligible	Positive
Regional	0.05	Minor	None Significant	None Significant
California	0.05	None Significant	None Significant	None Significant
Outside CA	Varies	None	None	None
SF	0.16	Yes	None Significant	None Significant
Regional	0.16	Minor	None Significant	None Significant
California	0.23	None Significant	None Significant	None Significant
Outside CA	Varies	None	None	None
SF	0.24	Yes	None Significant	None Significant
Regional	0.24	Minor	None Significant	None Significant
California	0.29	None Significant	None Significant	None Significant
Outside CA	Varies	None	None	None

CA	0.07	None Significant	Negligible	Positive
Outside CA	None	None	None	None
SF	None	None	None	None

A more detailed economic benefit analysis can be prepared once additional information is available about each project. In advance of that, we have utilized the NREL JEDI tool to create a high level estimate of jobs created (presented in Section 6.1.1) for each of the projects listed in Section 6.1.

To expand on this high-level estimation, the following information that would be required to develop a more in-depth analysis:

- **Total budget**, broken down by type of expenditure (materials and type of materials, labor costs).
- **Project schedule**. The availability and expiration of tax incentives related to renewable energy construction also has an impact on the procurement approach for determining City owned resources or privately owned resources with a lease arrangement for the City.
- **Program Design** for any Behind the Meter programs.
- **Location of expenditures** (in the City and County of San Francisco, in the SF Bay Region, in California, or outside California), broken down by type.
- **Cost of power produced,** along with assumption for cost of power without the project.
- **Tax or fee revenue generated** by the project or by end users (such as utility users tax).
- Application of any local procurement or hiring requirements.

Once the detailed and precise information for specific projects is developed, economic analysis can be performed for each option or project. For some types of data general assumptions can be used (such as the general proportion of costs that are labor, the source of the labor, and the mix of equipment expenditures). Also important to take into account are any potential City policies, such as recommendation by the Mayor's Renewable Energy Task Force that San Francisco's to meet 100% of its electricity demand with renewable power. [46]

[46] San Francisco Mayor's Renewable Energy Task Force Recommendations Report, September 2012: http://www.sfenvironment.org/sites/default/files/fliers/files/sfe_re_renewableenergytaskforcerecommendationsreport.pdf

2.2 Plan for Substitution of Local Power Supplies

CPSF will need to develop a strategy for managing the CPSF supply portfolio through the initial program start and as it evolves overtime. The initial CPSF supply portfolio will have been developed to achieve the target “green” energy supply portfolio at a price point that is competitive with equivalent PG&E supply rates. Initial product price and portfolio price certainty will drive the supply portfolio structure in the early stages of the program, most likely requiring some supply contracts of longer duration (to provide price stability) intermixed with shorter-term contracts to provide supply volume flexibility as the program gets off the ground. To the degree SFPUC PE can utilize Hetch Hetchy power in the CPSF supply portfolio, there is some built-in price certainty and volume flexibility.

In order to offer energy at acceptable rates, it will be necessary to consider projects located outside of the local area and to consider projects located on land not owned by SFPUC. It will also be necessary to determine the power cost parameter ranges that can feasibly support the green renewable energy plan offerings. For both the 100% renewable energy and the Light Green plan, the generation price points necessary to position the entire CPSF supply portfolio competitively with PG&E supply rates need to be determined so that the any renewable energy developed and procured fits within the CPSF portfolio price profile. A central objective and theme for CPSF is the support and development of local renewable generation that would be used to meet the supply needs of CPSF customers. As these local renewable generation projects are designed, developed and placed into commercial operation, CPSF will have to accommodate those new resources within the CPSF supply portfolio, thus the necessity of developing a rigorous CPSF supply portfolio cost strategy and price profile and promote and pursue only those renewable generation projects which align with the strategy and price profile.

The central issue will be the size and timing of cost-effective local generation resources being available to transition CPSF’s supply portfolio at the time that the local generation becomes available, which we assume will consist of contracts of varying size and term that will have been procured from the market. The lead time from project commitment, through development and ultimately commercial operation will represent a time window where CPSF will be required to actively manage the CPSF supply portfolio most likely through a combination of shortening the portfolio (i.e. relying more on a certain volume of shorter term market contracts as they approach the forecast project commercial operation date) and natural growth of the CPSF load as the program continues to expand. Variability in either project development and/or CPSF load growth represents price risk for the CPSF program that will need to be quantified, monitored and managed.

In addition to the issue of size and timing of local generation resource development, there is the issue of the type of generation being developed and how that may change the makeup of the CPSF portfolio. For example, development of large amounts of rooftop solar will potentially displace existing on-peak supply contracts but do nothing to impact off peak supply needs. The CPSF supply portfolio may start to evolve and have a larger portion of market-based contracts devoted to serving off peak (evening) load while a growing proportion of on-peak (daytime) load is served with local generation. The intermittent nature of many renewable resources (wind and solar) also represents a potential shift in the way CPSF will manage the supply portfolio, requiring higher reliance on the Day Ahead and Spot markets to firm supplies. The portfolio may become slightly more price volatile with greater participation in spot markets, so a price risk management strategy will need to evolve as the portfolio evolves to minimize risk exposures as the CPSF program grows.

CPSF will need to develop a comprehensive medium to long term supply strategy and create a portfolio management plan that identifies the size, type, and risk-adjusted expected timing for the addition of local renewable resources. This will be by necessity a working and living plan that will evolve as the program develops. This plan should be actively managed with (at a minimum) annual review[47] and updates as to market views and status of local renewable resource development (discussed further in Section 2.4 below). Just as importantly, CPSF will need to develop a risk management strategy, policy and process that are in lockstep with the resource planning to actively identify, quantify, monitor and manage portfolio risk as the CPSF program evolves.

2.3 Expand CPSF Customer Base

2.3.1 Initial Program Size

The currently planned 20-30 MW of demand planned for the initial phase of CPSF implementation can in part be traced to the SENA contract. Essentially, 20 MW was the minimum power procurement that Shell would contract for. However, the 30 MW size was also established by the SFPUC based on a desire to 1) ensure fiscal ability to roll back the program if the initial implementation phase was not deemed successful; and 2) obtain some actual data for the number of customers that will opt-out (which could be scaled up for subsequent phases).

Significant planning has subsequently been invested into detailing the initial 20-30 MW implementation phase. This planning includes the Section 1 assessment of SFPUC capability and capacity to manage the power supply portfolio for CPSF. A larger program would potentially require additional SFPUC personnel to manage but without the operational experience to understand what the incremental needs might be. As mentioned earlier, the estimate of 20-30 MW of customer load in the initial phase of the CPSF program was largely based on the initial power supply contracting strategy and the cost impact of credit security required by Shell Energy North America (SENA). The “resetting” of the program which includes having SFPUC PE manage the CPSF supply portfolio may introduce the opportunity to increase the initial program size, within constraints of doing so using only existing capability and capacity of SFPUC PE staff and operations. Determination of the potential incremental increase in initial program size that can

[47] The more dynamic the program, the more frequently the plan needs to be reviewed and updated. Conceivably, a monthly review may be needed, particularly if energy market volatility increases, creating potential windows for new renewable generation products to become cost effective relative to market alternatives.

be accommodated by existing PE staff is beyond the scope of this report but is identified as a key action item for SFPUC PE and CPSF to examine when the program moves forward.

2.3.2 Commercial Customers

The initial implementation plan focused on residential customers and even considered not offering CPSF service to commercial and industrial customers (C&I). CCA's are required to serve residential but not commercial customers per Assembly Bill 117. Subsequently, the rate structures for PG&E[48] have changed per CPUC decisions such that large commercial and industrial customers (>200 kW in demand) are defaulted to Critical Peak Pricing (CPP which PG&E calls Peak Day Pricing (PDP)) which has a discount for non-peak days but higher energy charges on the days with highest demand. All other non-residential customers now default to Time-of-Use pricing where electricity utilized during the day is more expensive than electricity used "off peak". CPUC expects to expand CPP to all non-residential customers. The change in PG&E supply rate structures could represent an incentive to SF C&I customers to embrace alternative energy supply cost structures that CPSF could offer that may represent less volatile and more predictable energy costs when compared to what they would get by staying with PG&E.

Commercial and Industrial customers are "higher margin" customers. For a typical utility like they usually comprise almost half of the electricity usage but only between 10-20% of the service accounts. This translates to more revenue per bill when each bill has operational expense associated with both delivery of electricity and related administrative aspects of customer service. Including Commercial and Industrial (C&I) customers in the CPSF expansion can increases the CCA revenue. Additionally, some businesses within San Francisco have indicated a desire to become CPSF customers. Therefore, including commercial customer accounts in the CPSF phased implementation plan is recommended. CPSF could take an approach for non-residential customers to positively elect to participate where commercial and industrial accounts would positively elect to join CPSF. Alternatively, CPSF could default non-residential customers to CCA service where they would "opt-out" to stay on either PG&E bundled service or with their current Electricity Service Provider (ESP)[49].

Table 9 Sample PG&E Tariff Rates[48]

[48] PG&E Tariff Book: http://www.pge.com/tariffs/ERS.SHTML#ERS

[49] Applicable to customers participating in Direct Access.

Peak	Part Peak	Off-Peak	Part-Peak	Off-Peak
$0.13717	$0.12836	$0.10156	$0.08572	$0.06652
$0.12319	$0.11551	$0.09217	$0.09308	$0.07306
$0.11322	$0.10774	$0.08679	$0.08485	$0.06846
$0.10902	$0.10402	$0.08506	$0.07950	$0.06445
$0.90	$0.90	$0.90		
($0.00702)	($0.00702)	($0.00702)		
($0.00800)	($0.00800)	($0.00800)		

[50] Sample generation charges for small commercial customer with less than 75 kW demand and less than 150,000 kWh energy consumption per year.

[51] Sample generation charges for small commercial customer with less than 500 kW demand.

[52] Generation charges for small commercial customer with less than 500 kW demand.

($0.00861)	($0.00861)	($0.00861)

2.3.3 Timing for Local Build-out of Generation Resources

A fundamental consideration for expanding beyond the proposed initial 20-30MW implementation phase will be whether to synchronize the build-out of local generation resources with the expansion of the CPSF program. If expansion of the customer base needs to align with the build-out plan, then contracts and projects for these local generation resources will determine the timing for rolling out the program to additional customers. Alternatively, procured power could be utilized to supply electricity needs in advance of local generation build-out in which case subsequent implementation phases could be independent of generation installation.

EnerNex recommends adopting program and management principals including lifecycle management to assist with the timing and planning of build-out efforts. Projects like CPSF usually begin with a vision and mission based on internal, customer-driven and/or external regulatory requirements. The strategy is then determined for complying with the requirement(s), developing a solution roadmap and carefully developing business priorities and identifying the potential risks associated with the potential solutions. After the strategy has been crafted, clear requirements are developed by creating or reviewing different scenarios for implementation. When the requirements are done, the business architecture can be developed with a high level view providing a clear picture of what needs to change in the organization (in this case SFPUC and CPSF), where cost issues will occur.

Once the CPSF has been approved, the organizational structure and system architecture needs to be reviewed to determine possible business and technology solutions to meet the requirements and implement the CCA. A portfolio of projects will need to be implemented to manage the initiation, deployment and implementation launch of CPSF.

Upon completion of the development activities, the solution needs to be integrated into SFPUC operations. This can be a challenging activity on several fronts. First, there is the technical challenge of keeping the operations running while implementing new solutions. Second, there are the business processes that are likely to change due to CPSF integration. Finally, there are the organizational challenges of implementing CPSF. All of these different aspects must be

[53] Generation charges for small commercial customer with less than 500 kW demand.

addressed in order to minimize the change-over risks and to realize the maximum operational value.

Figure 7: Recommended Project Life Cycle Approach

2.3.4 Customer Communications

In order to attract customers to CPSF, a clear articulation of the program will be needed. This equates to marketing of the program so customers understand the benefits of CPSF, the potential cost implications of participating in the program (versus PG&E) and other benefits of the program such as available "greener" energy products the and local control of rates and resources. There has been significant media attention on the CPSF program since its inception and there are strong feelings both advocating and opposing the program. Therefore, once program design is finalized, careful consideration and preparation of customer communications related to program launch is critical to alleviate or mitigate the concerns voiced by program opponents. The customer opt-out notifications cannot be overtly marketing material, but must inform eligible constituent customers of their right to opt-out of the CPSF program.

2.4 Compare Planned to Actual Build-out

In order to track program progress, an initial baseline plan and schedule for the 20-30 MW initial CPSF implementation (subject to program size re-evaluation) needs to be developed as well as a plan detailing the build-out of local renewable generation resources. There are many considerations to take into account regarding the implantation schedule for both the CCA and local resource build-out. For example, the federal solar investment tax credit (ITC) will be cut from the current 30 percent of the total solar project value to 10 percent in 2017. This fundamental change in tax incentives for solar power is only a few years away and significantly alters the financing consideration for the build out of solar generation. For example, a common method for municipal solar generation financing is for a private developer to build the solar generation station and lease it to the city or establish a long term power purchase agreement (PPA) for the output. The developer can take advantage of the 30% ITC and pass those savings along to the city where as the city would not be eligible for the ITC. However, after 2017, a 10% ITC may not provide enough financial incentive for a private developer to discount either the lease or the PPA price for the city when compared to a city's ability for relatively inexpensive financing through bonds, such voter approved Prop. H bonding, for projects such as solar generation investment.

Therefore, once SF LAFCo, SFPUC and the City authorize proceeding with implementation of CPSF a plan and schedule for proceeding can be developed to meet the milestones detailed within that authorization. Progress can be tracked relative to the initial plans and forecast costs compared with actual costs incurred. Most importantly, a proposed rate structure can be built based on actual power procurement RFO solicitation(s) to determine whether the envisioned Light Green or 100% renewable portfolio can be achieved while still being cost competitive with PG&E rates.

2.5 Conclusions: Economic Benefits

1) EnerNex recommends adopting program and management principals including lifecycle management to assist with the timing and planning of build-out efforts.
2) The development of local renewable energy has the potential to realize economic benefits for the City from the employment and expenditures for implementation activities and also from the shift of spending on energy from remote sources to sources within the City.
3) To maximize local economic benefits, the City should focus on local employment and procurement provisions, and establish a preference for projects that are physically located within the City and County of San Francisco. Methods of ensuring local benefits include the imposition of local contracting, procurement and hiring requirements, and from a preference for transaction structures (such as PPAs and PPPs) that provide for the eventual ownership of generation facilities by local entities.
4) A fundamental consideration for expanding beyond the proposed initial 20-30MW implementation phase will be to decide whether to synchronize the build-out of local generation projects with the expansion of the CPSF program or whether to use procured power to supply electricity needs in advance of local generation build-out. EnerNex

recommends adopting program management principals including lifecycle management and lifecycle costing to optimize the timing and planning of build-out efforts.

3 TASK 3: LOCAL BUILD-OUT PROGRAM

3.1 Energy Efficiency Outreach

Coordinating CPSF materials with the SFPUC is essential to ensure that San Francisco residents and businesses understand the complete range of programs, including EE programs available to CPSF customers through SF Department of Environment Climate and Energy Programs either currently or as expanded through collaboration with CPSF. In addition, as CPSF customers will be eligible for PG&E's EE programs as well as those from the Bay Area Regional Energy Network (BayREN), coordination of marketing material for these programs would benefit CPSF customers. The EE program promotion by CPSF would need to consider the impact of the EE programs versus the EE program costs which would ultimately be passed onto its customers.

One aspect of EE programs that may be considered in coordination with CPSF are programs that are not dependent upon CPUC funding and therefore would not need to be approved by the CPUC. However, the source of funding for programs that are independent of CPUC funding will need to be determined.

3.1.1 CCA Opt-out Information

A CCA must inform potential constituent customers at least twice within two months (60 days) prior to the customers' designated date of CCA enrollment[54]. Notifications must include the following information:

- The customer is to be automatically enrolled in the CCA;
- The customer has the right to Opt-Out of the CCA without penalty; and
- The terms and conditions of the services offered.

A similar opt out notification must be made twice within two billing cycles subsequent to a customers' enrollment in the CCA.

Marin Energy Authority (MEA) followed the required notification policy during their initial roll out, but revised their internal policy for the enrollment that occurred when the City of Richmond joined the Marin Clean Energy (MCE) program. The policy revision was based on customer feedback and included a third notification prior to the date of enrollment starting from 90 days instead of 60 days as required by CPUC. MEA also determined from customer feedback that notifications should be sent in both the form of postcards and letters in sealed envelopes.

[54] Electric Rule 23 customer notification requirements, November 29, 2006, page 10, http://www.pge.com/tariffs/tm2/pdf/ELEC_RULES_23.pdf

The opt-out material must include the terms and conditions of the services offered. Therefore the opt-out information should not be used as marketing for EE programs, but should ensure that potential CCA customers understand that by choosing the CCA, they will not be forgoing any EE, or solar, programs sponsored by PG&E.

In particular, it is important that the opt-out material indicate that the CPSF plans to offer its customers additional EE programs, while emphasizing that CPSF customers will continue to have access to both PG&E and BayREN EE programs. It would also be advisable to indicate in the CCA opt-out materials that future CPSF EE programs that are expected to be funded through the CPUC must be approved by the CPUC.

3.1.2 Energy Efficiency Website Information

SFPUC's "About CPSF" webpage mentions the proposed CCA EE programs i.e. CPSF will offer "energy efficiency programs for participating customers."[55] It is recommended that the website add information to energy efficiency programs currently available to customers and also add additional information on planned EE programs including at a minimum the plan for commercial, single and multi-family programs. Summarizing the already available SFPUC, PG&E and BayREN EE programs would be helpful to potential customers and would make it clear that all these EE programs will still be available to them in addition to the new CPSF EE programs.

An example the material that could be added can be seen on the MEA website. MEA provides materials on the implementation of EE programs on their EE-specific website[56]. A similar approach and associated marketing directing customers to the website would help publicize and inform potential customers of the programs benefits and details. It is recommended that the CPSF page focus on a customer friendly page that highlights the programs and benefits. It is not recommended to provide implementation plan details and specific filing documents as found on the MEA website.

As discussed in more detail in section 4, coordination and non-overlap of EE programs among CPSF, PG&E, SFPUC and BayREN would benefit CPSF customers.

3.2 Coordination with GoSolarSF

Coordination of projects with GoSolarSF would leverage funding and would increase benefits for CPSF customers. CPSF marketing materials can and should list all programs available to CPSF customers.

CPSF customers participating in EE programs should be informed of GoSolarSF opportunities and vice versa. CPSF programs should highlight the benefits of implementing EE first when referencing GoSolarSF. Adding solar to an inefficient home or business will not derive the

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[55] http://www.sfwater.org/index.aspx?page=577, retrieved August 15, 2014

[56] MEA EE specific website: http://www.marincleanenergy.org/ee

expected results. Therefore, participating contractors in the GoSolarSF can serve as a good starting point for customer outreach training on the proposed low income and multi-family EE programs. Long term, the CPSP could fund the GoSolarSF program, by integrating GoSolarSF into the overall CPSF local resource build-out plan.

3.3 Conclusions: Energy Efficiency Program Outreach

- CPSF should pursue funding of Energy Efficiency (EE) programs through the CPUC, as doing so will potentially increase funding overall for San Francisco's businesses and residents. Long term, the CPSP could fund the GoSolarSF program, by integrating GoSolarSF into the overall CPSF local resource build-out plan. Coordinating CPSF's CPUC-funded Energy Efficiency (EE) programs with those from PG&E's EE programs as well as those from the Bay Area Regional Energy Network (BayREN) will result in additional funding for San Francisco. After all CPUC EE funding options are fully utilized, the CPSF can consider additional self-funded EE programs. Self-funded CPSF EE programs would need to consider the impact of the EE programs versus the EE program costs which would ultimately be passed onto its customers. . CPSF customers participating in EE programs should also be informed of GoSolarSF programs.

4 TASK 4: ENERGY EFFICIENCY STRATEGY

CPUC Decision 12-11-015[57], dated November 8, 2012, authorized the MEA to spend over $4 million dollars on four EE programs. Funding for all four of the EE programs proposed by MEA was approved by the CPUC. Using a similar approach as MEA, CPSF can acquire EE funds authorized by the CPUC.

CCA's can use Energy Efficiency (EE) funds collected from their own customers as well as funds collected from the Investor Owned Utility (IOU) servicing their territory. How the CPUC treats a CCA's EE programs is determined by whether or not they are using IOU funds. Both approaches have been used by the Marin Energy Authority.

For 2012, MEA elected to access only the EE funds collected from its own customers. For 2013 and 2014, MEA requested authority to administer not only energy efficiency funds collected from MEA's customers, but also from other customers within PG&E's territory.

Use of EE funds is authorized under Public Utilities Code Section 381.1(a)–(d)[58]. The only distinction for CCAs, as opposed to other entities, is in Section 381.1(d), which states:

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[57] CPUC Decision 12-11-015 Approving 2013-2014 Energy Efficiency Programs and Budgets, November 15, 2012: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M034/K299/34299795.PDF

[58] California Public Utilities Code - Section 381.1http://codes.lp.findlaw.com/cacode/PUC/1/d1/1/2.3/7/s381.1

> "The commission shall establish an impartial process for making the determination of whether a third party, including a community choice aggregator, may become administrators for cost-effective energy efficiency and conservation programs pursuant to subdivision (a), and shall not delegate or otherwise transfer the commission's authority to make this determination for a community choice aggregator to an electrical corporation."

The Commission concluded that

> "Thus it appears the Commission itself must handle the selection of the CCA programs. In this way, the administrative structure for CCA programs is exactly the same as for the RENs {Regional Energy Networks} described above. Therefore, even though MEA's proposal for 2013-2014 is not defined as a REN, we treat it, for administrative purposes for this portfolio period, as if it were a REN. If MEA had elected to administer funds only from its own customers under Section 381.1(e) and (f), our conclusion would likely have mirrored our resolution on MEA's 2012 energy efficiency plan."

CPUC decision 12-11-015 approved MEA's request for $4,015,205 in EE funds for four 2013-2014 programs. The four EE programs are briefly summarized as:

- The **Multifamily Energy Efficiency Program** (MFEEP) provides incentives for multifamily residential buildings with incentives of up to $50 per unit, with a goal of a 15% total energy savings goal. The program also proposes to provide financing for the remainder of costs via an on-bill repayment mechanism. Approved Budget: $861,781
- The **Single Family Utility Demand Reduction Program** targets high-energy-consuming single-family homes within its service area. The program offers targeted marketing and on-line software to present options for high-energy-consuming users for both energy efficiency and renewable energy projects. The program does not propose to offer incentives, but rather is aimed at awareness and information which would lead to behavior and retrofit enhancements. Approved Budget: $851,400
- The **Small Commercial Program** offers incentives for multi-measure retrofits, initiated through targeted outreach. It provides technical support to small commercial property owners in high energy use segments which include, but are not limited to, restaurants, retail, and professional services. The program proposes three main sub-programs: convenience store and small grocer energy efficiency development; restaurant energy efficiency project; and professional services energy efficiency project. Approved Budget: $1,380,024
- The **Financing Pilot Programs** proposes both an On-Bill Repayment (OBR) program and a Standard Offer program to enable financing for underserved markets. MEA states that the OBR program will 1) streamline the loan application and enrollment processes, 2) offer customers and contractors support for wider and deeper retrofits, and 3) will leverage other MEA programs and services. The OBR program plans to partner with

private banks or financing entities to provide financing to building owners, with the repayment charge placed as a line item on the bill. MEA is somewhat unique in that it relies on PG&E for its billing, but controls certain line items related to its services. Approved Budget: $1,192,000

Cal Broomhead with SFE has stated that similar CPUC approved funds for CPSF could total between 20-30MW for a EE program with a budget of $4-$6 million[59].

4.1 Leveraging Initial Allocation Overview

During Phase 1, CPSF expects to have $2M allocated by the City for EE improvements with priority given to low income CPSF customers[60]. The CPSF Draft Build-Out Roadmap and Strategies document, recommends leveraging available funds by coordinating efforts with the Department of Energy (SFE) residential EE programs[61]. The Mayor's office of Housing and Community Development also has programs such as the Single Family Rehabilitation Program that can be leveraged. The contractor for the Single Family Rehabilitation Program provides EE services when they perform whole house renovations. In addition, the Economic Opportunity Council and other private groups assist in packaging low income affordable housing deals. The CPSF can apply for and, if successful, utilize EE funding from the CPUC to work with both public and privately funded organizations to jointly offer EE programs.

The draft roadmap states that multi-unit residential building within CPSF territory may be good candidates for energy retrofits focusing on common areas and facilities. EE programs should address various target customers and market segments. For example, low income residents and owners of low income buildings have different motivations depending on which costs they incur. Separate EE programs can target the entire building and common areas that are of interest to building owners while other programs can target individual units that would benefit low income residents directly through lower energy bills.

A portion of the GoSolarSF funding allocation is to low income properties[62], and using a similar approach a portion of EE fund programs can be targeted to low income residents. The draft roadmap strategy #3 calls for[63]:

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[59] Between $4-6 Million of a possible $8 EE project budget cited includes a possible CPUC approved transfer of $2-4 million of EE funding from PG&E to CPSF/SFPUC/SFE. As a result, the economic impact from the potential $4-6 Million transfer from PG&E may be a transfer of PG&E EE program economic impact to the CPSF/SFPUC/SFE EE program rather than incremental economic impact.

[60] San Francisco Board of Supervisors Resolution 0348-12 (adopted September 18, 2012)

[61] CleanPowerSF Draft Build-Out Roadmap and Strategies Draft, SFPUC Power Enterprise, June 2013, page 8

[62] CleanPowerSF Draft Build-Out Roadmap and Strategies Draft, SFPUC Power Enterprise, June 2013, page 14

1. Leveraging EE funds with existing programs that perform home improvements on low income properties
2. Prioritizing projects on the basis of cost-effectiveness.
3. Identify low income properties to leverage the initial allocation
4. Determine if the CPSF will have EE funds from other sources
5. Apply to the CPUC for EE funds

The CPUC utilizes a standard methodology for determining EE cost-effectiveness[64]. The CPSF can propose more forward thinking approaches to assessing EE cost effectiveness, and then allow the CPUC to consider whether or not to accept changes to the cost assessment methodology. In order to ensure approval of at least some of its proposed EE programs, the CPSF should propose some programs which are cost effective under the existing EE evaluation methodology. Doing so will allow for the possibility that the CPUC does not, at least initially, approve the new proposed EE cost assessment methodology.

4.2 Plan for Low Income Allocation

In addition to the above mentioned multi-unit residential buildings that CPSF would like to serve, targeting customers not currently being served and offering programs different from other currently available programs would be a good strategy in terms of securing CPUC funding. CPSF low income residents would benefit from additional programs and the CPUC will consider targeting underserved populations as a positive attribute of any proposed CPSF EE program. Further, the CPSF would be able to offer programs tailored to San Francisco that likely would better meet the City's needs rather than the lowest cost general purpose EE contractors selected by entities operating programs over large geographic areas.

As CPSF low income customers will also be eligible for PG&E's Energy Savings Assistance (ESA) program and by EE programs offered by SFPUC, offering different or complimentary programs would help serve a broad range of low income households.

Current PG&E low income EE programs include:

1) Energy efficient electric appliances
2) Weatherization
3) In home energy education
4) Education workshops

[63] CleanPowerSF Draft Build-Out Roadmap and Strategies Draft, SFPUC Power Enterprise, June 2013, pages 36-37

[64] CPUC Energy Efficiency Cost-effectiveness: http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/Cost-effectiveness.htm

Over its entire service territory, PG&E's programs treated 123,566 homes in the program delivering over 42,863,291 kWh's and 1,918,656 therm savings in 2013[65]. These numbers exceeded the goals set by the California Public Utilities Commission while coming in under budget.

Current SFPUC energy efficiency programs include:

1) Providing Energy Efficiency Resources educational material
2) Providing Residential EE educational material

Based on the draft roadmap strategy #3 points, and endeavoring to avoid duplicating existing PG&E and SFPUC EE programs, multi-family building and owner-occupied home repair EE programs would appear be good choices for CPSF's low income EE programs. Analyzing budgets from both MEA's EE program and PG&E's low income ESA program, a proposed budget for the initial allocation of the $2M for EE funding is illustrated in Table 10.

Table 10 Proposed Budget for initial $2M allocation of EE funding

Multi-Family Residential	$660,000.00
Single Family Residential	$300,000.00
Commercial	$220,000.00
Pilots	$120,000.00
General Administration	$170,000.00
Measurement & Effectiveness Studies	$20,000.00
Regulatory Compliance	$20,000.00
Marketing & Outreach	$130,000.00
Education & Training	$360,000.00

[65] Energy Savings Assistance (ESA) Program and California Alternate Rates for Energy (CARE) Program Annual Report For Program Year 2013 page ii

http://www.liob.org/docs/PGE%202014%20%28PY%202013%29%20ESA%20&%20CARE%20Annual%20Report.pdf

4.3 Priorities and Resources

Funding for CPSF's EE programs can be provided by the CPUC, DOE, the CEC and other government agencies. CPUC EE funding can be allocated in 2 to 3 year funding cycles (although CPUC is currently considering a 10 year cycle). CPSF could apply for EE funding for the next funding cycle which begins in 2016. To apply, the CPSF will need to file an EE program Implementation Plan with the CPUC by approximately February 2015.

Priority for funding should align with the roll out plan for other customers. There are tremendous resources available within the agencies in the SFPUC and the Department of Environment that can be leveraged for future EE programs. It is recommended to coordinate planning with the BayREN and SFE to not duplicate efforts already being planned. The CPUC will require CPSF to follow the same requirements as the RENs and the IOUs.

The CPUC requires that EE programs be cost effective and lead to direct energy savings. In addition the CPUC will provide funding for unique programs proposed by CPSF that do not duplicate programs currently offered by PG&E. PG&E currently has over 120 active programs that are available to potential CPSF customers. PG&E's programs in 2013 exceeded their goals set by the CPUC[66]. The active PG&E programs were reviewed to identify unique programs for CPSF that would achieve the goal of driving energy efficiency in the City of San Francisco and position CPSF as a model for other CCA's. A list of possible programs to consider for CPSF includes:

- Small commercial program targeting specific segments underserved by PG&E. To determine segments further analysis will need to be completed. Existing resources in the Department of Energy could be used to market to these customers and drive implementation of projects.
- Financing for smaller commercial customers that do not meet the minimum loan requirements of PG&E's On Bill Financing (OBF) program. The current minimum loan amount in the OBF program is $5,000 which limits participation from small business customers that need funding for projects under $5,000.
- Financing for targeted technologies that exceed the payback criteria of PG&E's OBF program[67]. The OBF program provides financing for projects with a 5 year of less simple payback. Offering financing for projects that exceed a 5 year simple payback would help

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[66] PG&E 2013 Energy Efficiency Annual Report page 1
http://eestats.cpuc.ca.gov/EEGA2010Files/PGE/AnnualReport/PGE.AnnualNarrative.2013.1.pdf

[67] Pacific Gas and Electric Company , On-Bill Financing Customer and Contractor Handbook, 2014: http://www.pge.com/includes/docs/pdfs/mybusiness/energysavingsrebates/rebatesincentives/taxcredit/onbillfinancing/handbook_obf.pdf

drive the adoption of emerging technologies and other targeted technologies which would drive energy efficiency savings for CPSF.

- Pilot programs to target specific stressed areas on PG&E transmission grid. Possible programs could provide increased incentives above and beyond PG&E's incentives. This would ensure CPSF customers have a reliable power source and would lead to direct energy savings.

Benchmarking what other Northern California CCAs have implemented for CCA:

- MCE's offerings include:
  - Residential EE program includes:
    - An interactive web-based My Energy Tool to help customers identify energy saving measures; and
    - Green Home Loan program to cover the upfront costs of energy saving upgrades with repayment directly on the PG&E bill.
  - Multi-Family EE program includes:
    - No-cost energy assessments and technical assistance;
    - Incentives and rebates[68]; and
    - Green Property Loans.
  - Small Business EE program includes:
    - A no-cost building energy assessment;
    - Pre-negotiated pricing with qualified contractors;
    - Incentives and rebates[69]; and
    - MCE's Green Business Loans.

4.4 Conclusion: Energy Efficiency Strategy

1) CCA's, including CPSF, can use Energy Efficiency (EE) funds collected from their own customers as well as funds collected from the Investor Owned Utility (IOU) servicing their territory. The CPUC requires that EE programs be cost effective and lead to direct energy savings. In addition the CPUC will provide funding for unique programs proposed by CPSF that do not duplicate programs currently offered by PG&E.

[68] Free multi-family dwelling measures include high efficiency lighting, faucet aerators and showerheads, and hot water pipes insulation wrapping with insulation.

[69] SmartLights offers technical assistance and instant rebates (typically range from 25%-75% of total project costs) to help defray the cost of upgrading and/or repairing existing equipment.

2) There are tremendous resources available within the agencies in the SFPUC and the Department of Environment that can be leveraged for future EE programs. It is recommended to coordinate planning with the BayREN and SFE to not duplicate efforts already being planned.
3) A list of possible programs for CPSF includes small commercial program targeting specific segments underserved by PG&E, financing for smaller commercial customers that do not meet the minimum loan requirements of PG&E's On Bill Financing (OBF) program, financing targeted at technologies that exceed the payback criteria of PG&E's OBF program.
4) CPSF expects to have $2M allocated by the City for EE improvements with priority given to low income CPSF customers. Program design details are not known for the EE incentive design such as a rebate reimbursing the homeowner, business or resident for a certain percentage of the purchase price for more energy efficient equipment. However, it is expected that the economic impact for spending on the installation of EE equipment will generate 6.6 jobs for each $Million expenditure which includes the total spent on EE improvements by both the program as well as the customer.
5) Between $4-6 Million of the possible $8 EE project budget cited includes a possible CPUC approved transfer of $2-4 million of EE funding from PG&E to CPSF/SFPUC/SFE. As a result, the economic impact from the potential $4-6 Million transfer from PG&E may be a transfer of PG&E EE program economic impact to the CPSF/SFPUC/SFE EE program rather than incremental economic impact.

5 TASK 5: COMMERCIAL AND INDUSTRIAL CUSTOMERS

5.1 Attracting Commercial Customers

Per the CPSF Draft Build-Out Roadmap and Strategies[70], CPSF had not planned to include commercial and industrial (C&I) customers in the initial CCA rollout phase. However, Commercial and Industrial customers are "higher margin" customers. They comprise 36% of all US electricity use[71] but represent only between 10-20% of the service accounts. This translates to more revenue per bill when each bill has operational expense associated with both delivery of electricity and related administrative aspects of customer service. In addition C&I customers are

[70] CleanPowerSF Build-Out Roadmap and Strategies Draft, SFPUC Power Enterprise, June 2013, page 10

[71] Building Technologies Office, Commercial Buildings Integration Program web site, http://energy.gov/eere/buildings/about-commercial-buildings-integration-program

by definition large customers so offering them service has a larger impact on the City's goals which include improving energy efficiency, increasing San Francisco's use of clean renewable energy and increasing local jobs.

Thus, large high margin Commercial and Industrial customers are desirable for the CCA. It should be noted that Assembly Bill 117 (AB 117) requires that all residential customers be offered the opportunity to purchase electricity through the CCA[72] but does not require that C&I customers be served. The CPUC-approved City of Lancaster, California Community Choice Implementation Plan has a phased implementation plan[73] that offers service to non-residential customers before rolling out CCA services to residential customers. Thus if the CCA rolls out its services incrementally as is the current plan, it may consider offering service to C&I customers prior to adding residential customers in a subsequent enrollment phase.

The SFPUC has a list of C&I customers who proactively indicated that they want to participate in a 100% renewable program when it becomes available. Note the list of proactive C&I customers was compiled when rates were expected to be significantly higher than PG&E rates, and with no direct marketing. Thus, there is a known existing set of potential commercial customers for the CCA. Including Commercial and Industrial (C&I) customers would increase the CCA revenue in the near term. As a result, it is recommended that CPSF consider C&I customers for inclusion in the early CCA rollout phases. One method of doing so would be to designate a percentage of the initial power available to commercial businesses who have requested 100% renewable energy.

Effective EE programs would further incentivize commercial customers to join the CPSF CCA as EE programs reduce participants' energy costs. Funding from the CPUC could support new EE programs including those for commercial customers. Figure 8 illustrates the largest electricity end uses by residential and commercial customers that indicate areas for potential EE target incentives.

Commercial EE programs could help attract C&I customers by offering cost saving benefits to commercial firms which would in turn help promote economic benefits including additional jobs in San Francisco.

[72] AB 117, Amended, August 27, 2002, Section 4, 366.2 (3)(b), http://www.leginfo.ca.gov/pub/01-02/bill/asm/ab_0101-0150/ab_117_bill_20020827_amended_sen.html

[73] Lancaster Choice Aggregation Community Choice Aggregation Plan Final, June 2014, Section 5.4

Table 2-3. Largest Residential and Commercial End Uses

Electric Sector and End Use	Percent of Total Electricity Use
Com Indoor Lighting	17%
Com Miscellaneous	13%
Res Miscellaneous	10 %
Com Space Cooling	8%
Res Refrigerator	8 %
Res Lighting	7%
Com Ventilation	6%
Com Refrigeration	4%
Res Space Cooling	4%
Com Outdoor Lighting	3%
Res Dryer	2%
Res Water Heater	1%
Total	84 %

Gas Sector and End Use	Percent of Total Gas Use
Res Space Heat	32%
Res Water Heater	16%
Com Heating	11%
Com Water Heating	10%
Res Clothes Washer	7%
Com Cooking	7%
Res Dishwasher	5%
Total	87%

Source: Navigant team analysis of CEC 2011 IEPR demand forecasts (Mid-case).

Figure 8: CPUC 2013 California Energy Efficiency Potential and Goals Study Table 2.3[74]

An effective strategy for CPSF would be to propose EE commercial programs for underserved markets and to follow Marin Energy Authority (MEA) lead in establishing EE programs. MEA successfully secured funding for four EE programs that approved by the California Public Utility Commission (CPUC)[75]. Two of MEA's four approved EE programs target commercial businesses, the Small Commercial Program and Financing Pilot Programs.

Initially, MEA decided to offer its EE programs only to its CCA customers. For CPSF, it might seem reasonable to offer its programs to both its own CCA customers and to customers served by the SFPUC. However, as the CPUC requires benefits to go to the customers who contribute to the EE funds which include CPSF customers, but not SFPUC customers, it may be easier to secure CPUC approval for programs which do not intermingle SFPUC and CPSF funding and customers.

MEA's Small Commercial Program targets business owners with high energy usage including restaurants, retail and professional services[76]. As San Francisco has a high percentage of businesses that fall in these categories, a similar CPSF Small Commercial Program would likely be

[74] 2013 California Energy Efficiency Potential and Goals Study, California Public Utilities Commission, November 26, 2013: http://www.cpuc.ca.gov/NR/rdonlyres/29ADACC9-0F6D-43B3-B7AA-C25D0E1F8A3C/0/2013CaliforniaEnergyEfficiencyPotentialandGoalsStudyNovember262013.pdf

[75] Decision Approving 2013-2014 Energy Efficiency Programs and Budgets, pages 51-52, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M033/K171/33171249.PDF

[76] Decision Approving 2013-2014 Energy Efficiency Programs and Budgets, page 49

viewed favorably by the CPUC. The CPSF Draft Build-Out Roadmap and Strategies identifies small- to medium-sized commercial customers as likely CPSF CCA customers and states these firms include restaurants, green businesses, retail stores, and professional service firms[77].

A plan to attract commercial customers could consist of the following steps:

1) Starting with the SFPUC's list of C&I customers who wish to participate in a 100% renewable program, identify potential CPSF commercial customers and building owners already engaging and working with the City. Target businesses supporting green initiatives, and commercial building owners. An effective means of identifying commercial customers would be to consolidate existing lists of business contacts maintained by various City departments.
2) Canvass business districts directly. The Department of Environment had good success canvassing business corridors. Therefore, direct canvassing of business owners would help identify commercial businesses interested in joining the CCA and participating in EE programs. Although MEA had limited success using neighborhood canvassing[78] to attract interest in its Small Commercial EE plan, based on past Department of Environment success, direct canvassing would identify business owners interested in both the CCA and its EE programs. .
3) Contact business community groups. Direct contact with commercial business stakeholders through groups such as the San Francisco Chamber of Commerce would likely generate interest in the EE programs and in the CCA and is therefore recommended.
4) Schedule meetings or workshops to solicit input with groups that represent SF business communities. Stakeholder inputs on desirable EE programs would help identify programs that would attract commercial customers who would then be more likely to select CPSF as their energy provider. Presenting EE plans to commercial stakeholders would also serve to introduce them to the CCA and its other benefits.
5) Develop draft commercial EE program plans. Suggested programs include:
   a) Small Commercial Program patterned after MEA's CPUC-approved program which targets commercial buildings and offers energy assessments, pre-negotiated discounts, project management, post-project quality assurance and low cost loans. Potential energy efficiency projects could include lighting, heating, ventilation and air conditioning (HVAC), refrigeration, food service, and building envelope upgrades. The Department of Energy has a successful retrofit program that has successfully retrofitted 5000 small

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[77] CleanPowerSF Build-Out Roadmap and Strategies Draft, SFPUC Power Enterprise, June 2013, Page 9

[78] Marin Clean Energy 2015 Energy Efficiency Program Portfolio Changes Pursuant to the Assigned Commissioner's Ruling and Scoping Memorandum Regarding 2015 Portfolios, rulemaking 1311-005, filed November 14, 2013, page 6

business and over 1000 medium to large commercial buildings with energy efficient lighting and refrigeration upgrades. Thus it is likely that additional EE programs would be viable options for the CPSF.

b) Innovative pilot programs that offer new technologies would help both the CCA and the City advance EE benefits including lower costs and reduced energy usage. Pilot EE projects could include:
   i) Resource Adequacy programs which reduce the CCA's RA costs
   ii) Direct Current (DC) lighting systems
   iii) DC microgrids for computer and other native DC devices
   iv) Solar PV electric vehicle charging stations

6) Conduct workshops with SF business communities to receive feedback from business communities. Present highlights from the draft commercial EE program plans. Solicit inputs from commercial building owners and commercial businesses on modifications to existing plans and additional EE programs that would be valued by the business community.
7) Based on workshop feedback, refine the proposed EE programs to meet the needs of SF businesses. Propose specific programs identified from the workshops that would attract customers to the CCA.
8) Develop the EE Program Implementation Plan. In order to secure CPUC funding, an EE Program Implementation Plan will need to be written and submitted to the CPUC approximately 6 months before the EE funding is authorized. The CPUC typically funds EE programs in 2-3 year cycles. A potential schedule strategy for CPSF would be to align the start of commercial EE programs with the earliest time when C&I customers would be accepted into the CCA.
9) Submit the EE Program Implementation Plan to the CPUC for approval and respond to filings from other entities which might seek to request the CPUC not fund the CPSF EE programs.

5.2 Pilot Programs for Commercial Subsidies

MEA's Financing Pilot Programs targets building owners and provides financing for EE programs with On Bill Repayment (OBP)[79]. The MEA OBR program will collaborate with private banks or financing entities to provide the financial backing for the pilot programs.

A pilot program for commercial EE projects would serve to help induce commercial customers to join the CPSF CCA. Because commercial buildings consume 36% of all US electricity[80], and

[79] Decision Approving 2013-2014 Energy Efficiency Programs and Budgets, page 50

because SF is a leader in green commercial buildings, energy efficiency programs targeted at commercial buildings would likely attract customers to the CCA.

5.3 Demand and Resource Adequacy

For the CPSF CCA, reducing demand during a limited number of time periods when energy costs are high could result in significant cost savings. The CAISO has transitioned their day-ahead and real-time wholesale electricity market for day-ahead and real-time electricity to reflect Locational Marginal Pricing (LMP). As a result, electricity pricing at different geographic Pricing Notes (pNodes) varies depending upon: 1) the cost of generation; 2) the distance between the generation source and the pNode; and 3) the congestion of the transmission capacity between the generation and the pNode.

Mitigating the cost to serve high cost areas with Demand Side Management (DSM) resources, including Demand Response (DR) through tactical dispatch of DR triggered by wholesale electricity prices, can prove to be a cost effective approach. Local resources including DR can cost more per Megawatt (MW) compared to bulk generation resources, but still be less expensive when taking the total cost of electricity delivery into and/or the CAISO market price spikes into account.

The value of DR is primarily related to its capacity value (ability to provide MW when needed) which equates to as Resource Adequacy[81] in California. DR is not a resource that aligns well with the need to provide energy on a daily basis to serve the demand and load of electricity consumers. Rather, it is the ability of DR to occasionally reduce energy usage to mitigate or minimize the impact when there is an unforeseen contingency event in generation supply or within the transmission or distribution system as reflected in CAISO market price spikes. When something unexpected affects the grid, DR can be dispatched to reduce the demand to help alleviate and mitigate the problem. The value attributed to capacity in California is correlated with Resource Adequacy with CPUC jurisdiction rather than through a CAISO wholesale capacity market with CAISO (whereas other states have wholesale capacity markets).

CPUC Decision14-03-026[82] “Addressing Foundational Issue of the Bifurcation of Demand Response Programs” split existing IOU DR programs into “load modifying” and “supply side DR programs”. Load modifying DR programs are typically rates and tariff pricing like Time of Use, Critical Peak Pricing and Peak Time Rebate which have the effect of reducing or modifying electricity demand and usage. Supply side DR are dispatchable programs that can or should be

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[80] Building Technologies Office, Commercial Buildings Integration Program web site, http://energy.gov/eere/buildings/about-commercial-buildings-integration-program

[81] California Public Utilities Commission, Resource Adequacy: http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/

[82] California Decision 14-03-026 Addressing Foundational Issue of the Bifurcation of Demand Response Programs, April 4, 2014: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M089/K480/89480849.PDF

integrated into the CAISO wholesale electricity market and would be bid and dispatched in competition with other CAISO market participating resources. A probable outcome after bifurcation is for “load modifying” DR to have the effect of reducing the LSE RA requirement itself (through an adjustment to the baseline load forecast curve) while “supply side” DR would help meet the RA requirement.

The Demand Analysis Working Group (DAWG) stakeholder group initiated by the CEC develops the protocols for determining load impacts and determining their effect on RA requirements. Because of the importance of RA to determining the value of DR, it is recommended that SFPUC consider participation with the DAWG to understand and influence DR load impact accounting.

5.3.1 On-site Control Technologies

On-site control technology including cycling of air conditioners (e.g. the PG&E SmartAC program[83]) has been successfully implemented for both commercial and residential customers. PG&E programs are offered across their entire territory and thus may not be widely used in San Francisco. For example the SmartAC program may not be widely used by small businesses because may do not have air conditioning. PG&E also offers a variety of programs for commercial customers including:

- Programs for small businesses
  - SmartAC
  - Home and Business Area Networking (HAN) allowing customers to view their electricity consumption in near real-time, via their SmartMeter™.
- Programs for medium to large businesses
  - Peak Day Pricing to save money for electricity usage reduction while conserving energy during times of peak demand.
  - Base Interruptible Program for reducing electricity demand to a specified level during electricity grid reliability mitigation events
  - Demand Bidding Program to reduce consumption when notified of a DR event day.
  - Scheduled Load Reduction Program with incentives to reduce consumption to a previously agreed level during a specified time selected in advance.
  - Optional Binding Mandatory Curtailment Plan to help avoid rotating outages during high demand periods.
- Aggregator Programs managed by 3rd Party Demand Response Providers (DRPs)
  - Aggregator Managed Portfolio to provide price-responsive Demand Response.

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[83] Pacific Gas & Electric SmartAC program: http://www.pge.com/en/myhome/saveenergymoney/plans/smartac/index.page?

    - Capacity Bidding Program to reduce energy by a previously agreed amount
- Technology Incentives:
    - Automated Demand Response (AutoDR) Incentive providing funding to help businesses pre-program energy management and control systems.
    - Permanent Load Shift incentive to installing equipment that facilitates shifting usage utilizing thermal energy storage technologies.

Building Automation and Control Systems (BACS) utilized by commercial customers use techniques which include adjusting lighting and air conditioning to reduce or in some cases increase demand to balance load with available energy supplies. BACS can interact with the Automated DR technologies like OpenADR[84] to automatically respond to DR events. Downtown San Francisco contains many large buildings with Building Automation and Control Systems which can be further optimized for both EE savings as well as DR capability. Working with building owners to implement OpenADR enabled interfaces with BACS holds the promise of significant DSM capability. However, CPSF will need to overcome initial resistance of building managers to participate in programs that have the capability to modify the building environment.

5.3.2 EE and Resource Adequacy Program

One of MEA's Pilot Programs offers savings based on EE programs that reduce Resource Adequacy (RA) costs. As part of the Financing Pilot Programs, MEA will offer a pilot program that offers a fixed payment per unit for vendors who deliver Resource Adequacy (RA) services to MEA[85]. Because the CPSF will need to meet RA requirements, a similar program might be a win-win program for both the CPSF and the pilot participants.

Rather than direct savings from EE, the benefit is realized through indirect reduced costs for RA. A third party vendor is being used for implementation[86]. MEA's EE implementation plan states that the program is modeled after similar plans in place in Texas and New England[87].

5.4 Existing Programs and Connections

Federal, state, local public, private and non-profit organization's community connections can be used to maximize the effectiveness of limited resources. Existing departmental connections, resources and expertise can and should be leveraged. The list of resources and connections that can be utilized include:

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[84] OpenADR Alliance: http://www.openadr.org/

[85] Decision Approving 2013-2014 Energy Efficiency Programs and Budgets, page 50

[86] MEA Energy Efficiency Program for 2013-2014, Program Implementation Plan, July 16, 2012, page 74

[87] MEA Energy Efficiency Program for 2013-2014, Program Implementation Plan, July 16, 2012, page 73

1) Energy-related and environmental non-profit organizations located in San Francisco including the Sierra Club, the Energy Foundation and the Natural Resource Defense Council--all of which are headquartered in San Francisco.
2) Business groups including the San Francisco Chamber of Commerce, the Hispanic Chambers of Commerce of San Francisco (HCCSF), the San Francisco African American Chamber of Commerce (SFAACC) and the San Francisco Chinese Chamber of Commerce.
3) The Department of Environment's expertise in canvassing commercial corridors which can be used to develop similar programs for the CCA.
4) The SFPUC's list of customers who wish to join the CCA as soon as it is available which can be used to identify highly motivated supporters for the CPSF

Section 1 contains additional details on leveraging SFPUC resources for managing the CCA's energy procurement process, Section 4 contains additional details for leveraging EE program resources, and Section 8 contains additional details for leveraging the GoSolarSF program's resources.

The CPUC and other government funding agencies will look favorably upon programs which leverage resources to provide comprehensive EE programs. Resources which can and should be leveraged include SFPUC's existing San Francisco Green Energy Program and programs similar to the DOE's Energy Efficiency and Conservation Block Grant Program (EECBG).

Although not permanently available funding, the California Energy Commission (CEC) offers programs which provide funds for advanced EE solutions. As an example, CEC Program Opportunity Notice (PON) 13-301[88] offers funding for programs in the following EE areas:

- Advanced lighting systems and components
- Advanced heating, ventilation, and air conditioning (HVAC) technologies and refrigeration systems
- Advanced building envelope systems and materials
- Improved understanding of occupant behavior to increase energy efficiency improvements in buildings
- Improved plug load devices
- Technologies and approaches that achieve the state of California's zero net energy (ZNE) goals

[88] California Energy Commission, Program Opportunity Notice (PON-13-301) *Developing a Portfolio of Advanced Efficiency Solutions: Technologies and Approaches for More Affordable and Comfortable Buildings*, March 21, 2014: http://www.energy.ca.gov/contracts/epic.html#PON-13-301

Although the CEC programs are typically competitive, partnering with third parties with a proven track record of winning CEC contracts could result in additional funding for CPSF programs.

5.5 Conclusions: Commercial and Industrial Customers

1) The current plan calls for CPSF to offer service to residential customers only. In addition to serving residential customers, CPSF should consider offering service to commercial customers especially those businesses who have already indicated that they want to enroll in a high content renewable energy plan. Including commercial customers will significantly increase the amount of renewable energy used in San Francisco, while at the same time increasing revenue for the CPSF.
2) Commercial and Industrial (C&I) customers are "higher margin" customers that generate more revenue per bill and this is one of the reasons that we recommend that the CPSF offers service to non-residential customers in Phase 1. In addition, large customers would have a the potential for a greater impact on the City's goals for improving energy efficiency, increasing San Francisco's use of clean renewable energy and creating or supporting local jobs. Thus, large C&I customers should be encouraged to join the CPSF. Recommendations for attracting C&I customers include offering commercial EE programs, utilizing SFPUC's list of C&I customers who proactively indicated that they want to participate in a 100% renewable program, and neighborhood canvassing of business corridors.
3) The current plan is for phase 1 to serve residential customers with 20-30 MWs of renewable energy. A phased implementation process is recommended which will add additional customers and the Light Green option. For example, Phase 2 could offer service to C&I customers, and Phase 3 could add the Light Green option.

6 TASK 6: RENEWABLE ENERGY PRODUCTION AND PURPOSES

A cornerstone and integral component of the CPSF program is renewable technology selection and site identification, build-out and integration of adjacent or in-city clean energy generation projects and energy efficiency programs. The plan is for the local clean renewable energy obtained through the build-out to be incorporated into the CPSF energy supply portfolio, where it will be used to meet the continuing needs of CPSF customers as the program builds and expands.

One of the initial goals of the CCA Program is to provide 50% or more of program supply through local and regional sources, including BTM and EE programs, within the first 10 years. Ideally, renewable projects would be located in-city and would create local jobs for San Francisco residents. However, the most economically viable renewable energy projects are located outside of the City. Some potential projects are located on SFPUC owned land such Sunol which are located outside of the City. These projects offer cost-effective solutions, and other cost-effective projects would be on non-SFPUC land with energy from these sites acquired through PPAs.

This section evaluates the potential for local build out of renewable energy including four sub sections:

6.1: Identification of Potential Sites: Work with SFPUC Power Enterprise staff (e.g. Renewables group, Energy Efficiency group) to develop a plan for identifying potential sites for build-out with initial focus on exiting site selection list.

0: Evaluate Small Hydro Investments: Evaluate potential for CPSF to invest in small hydroelectric power programs. Develop an analysis of economic benefits for CPSF and its ratepayers.

0: Evaluate Potential for Sunol Solar Project: Determine whether a solar project in Sunol would be a cost-effective investment for CPSF customers. Determine what future steps are necessary if the solar project is cost-effective.

6.4: Investigate Ratemaking Policies: Investigate prospects for petitioning the CPUC to change the ratemaking policy that requires CCA customers to pay for transmission services they do not use.

6.1 Identification of Potential Sites

EnerNex utilized inputs from LAFCo, Local Power Incorporated (LPI) and the SFPUC Power Enterprise staff (e.g. Renewables group, Energy Efficiency group, Water Department) to develop a plan for identifying potential sites for build-out with the focus on the existing site selection list. Potential sites for local build out of renewable generation projects have been identified by previous work conducted by and for the SFPUC. With some caveats, the renewable sites evaluated by SFPUC form a good starting point for local build-out projects. This section presents a plan for identifying potential sites for build-out with the initial focus on the existing site selection list.

Previous analyses, performed by SFPUC, have identified potential sites for solar photovoltaic (PV), wind, small hydro and geothermal renewable energy projects. Specific sites have been identified in multiple reports and analyses including SFPUC's Renewable Energy Assessment Final Report[89] prepared by Black and Veatch, LPI's Key Business Case and Financial Deliverable and SFPUC/CCSF's Potential Project List.

Estimated costs have been calculated for solar PV, wind and geothermal projects respectively and are summarized in Table 11, Table 12, and Table 13. Table 11 identifies the largest and most suitable PV sites from the data available from SFPUC/CCSP, LPI and Black and Veatch. In some cases, the estimated costs for solar projects differ significantly. Additional analysis of cost

[89] San Francisco Public Utilities Commission, Renewable Energy Assessment Final Report, 10 January 2014

estimates for solar projects are thus advised to verify the economic viability of specific solar projects. However, in general the cost for solar energy is continuing to decrease and solar is expected to reach economic parity with traditional generation in the near future[90]. Table 12 identifies potential wind projects. Table 13 identifies geothermal project costs for existing sites located in California. Note that geothermal sites are limited and that developing geothermal typically requires assuming more risk than other types of renewable energy because steam field developers generally will not offer steam production guarantees.

In the tables, the Levelized Cost of Energy (LCOE) column provides the best method of comparing costs between the various renewable energy projects[91]. Another relevant factor to consider is the difficulty of meeting environmental and land ownership requirements. A significant concern in reviewing the prior work is that for several specific projects, the LCOE varies considerably between the various entities doing the analysis. This indicates a potential for different assumptions applied in the different entities analyses. Thus prior to build out, further analysis is necessary to validate the estimated costs of specific renewable energy projects, especially solar projects. The cost differences may simply be due to the fact that the costs for solar have fallen. As solar prices are continuing to decrease, estimated costs of solar are likely currently less than even the earlier estimates.

For example, LCOE costs for Sunol range from $112.60 - $167.00 (LPI's estimate) to $80.48 (Black & Veatch's estimate) cents per megawatt hour. Based on the available LCOE data, the best sites for local San Francisco renewable energy build-out are:

- Solar PV at Sunol on city-owned land and
- Solar PV at Tesla Portal

Both Black & Veatch and LPI identified Sunol as the having the lowest LCOE for local solar projects. Although the data is preliminary, small hydro projects identified by the Water Department have low LCOEs as well. In-City wind projects are more expensive than the most cost-effective solar projects, although regional wind generation from close locations such as Altamont have low LCOEs.

Provided more detailed analysis of small hydro projects agrees with the SFPUC's high level screening and our estimated LCOE's, then the Small hydro projects identified in Section 0 would also be cost effective projects. Additional small hydro projects may also have low LCOE's which will need to be verified with further analysis. Warnerville substation may also be a cost effective solar PV site; however, acquiring rights to the privately owned land would appear to raise the

[90] Green Tech Media: Solar Parity is here Today, http://www.greentechmedia.com/articles/read/New-Study-Solar-Grid-Parity-Is-Here-Today

[91] The levelized cost of energy (LCOE) provides a simple method to compare distributed generation (DG) renewable energy technologies and combines capital costs, operations and maintenance (O&M), performance, and fuel costs.

effective cost of the project. Although the LCOE for the in-city Oceanside wind project has an attractive LCOE, we believe that the amount of effort required to secure permitting for a single 0.2 MW wind plant would be excessive in terms of the energy generated.

Next steps for pursuing the Sunol project are contained in Section 0. Details of the small hydro projects are contained in section 6.2. Moving forward the federal 30% credit for solar systems, currently scheduled to expire at the end of 2016, may impact the economic viability of the Sunol project. However, long term price declines in solar prices are likely to continue[92] (although at a slower pace than recent history) which may offset the potential loss of the federal tax credit.

Table 11 Largest and Most Suitable Potential PV Projects[93]

LPI[94]	3,500,000	35	$140M - $210M	4.00 - 6.00	112.60[95] - 169.00
SFPUC[96]	4,000,000	24.64	$168M	5.25	N/A
Black & Veatch	N/A	N/A	N/A	N/A	N/A

[92] Levitan, Dave, For Utility-Scale Solar Industry, Key Questions About the Future, paragraph 18, http://e360.yale.edu/feature/for_utility-scale_solar_industry_key_questions_about_the_future/2713/

[93] SFPUC Review of LPI Key Business Case and Financial Deliverable, slide 5, January 22, 2013

[94] SFPUC Review of LPI Key Business Case and Financial Deliverable, slide 5, January 22, 2013

[95] LPI LBOE costs assume 30% federal tax credit 2016 and bonus deprecation per the American Taxpayer Relief Act of 2012, which expires at the end of 2016

[96] SFPUC/CCSF Potential Project List, July 15, 2014

LPI	2,000,000	20	\$80M - \$120M	4.00 - 6.00	112.60 - 169.00
SFPUC	2,178,000	13.4	\$91.5M	5.25	N/A
Black & Veatch[97]	4,356,000	19.2	\$47.9M[98]	2.28	80.48
LPI	500,000	5	\$20M - \$30M	4.00 - 6.00	112.60 - 169.00
SFPUC	276,000	1.7	\$11.6M	5.25	N/A
Black & Veatch	348,480	1.6	\$5.5M	2.67	85.40
LPI	1,000,000	10	\$50M - \$70M	5.00 - 7.00	140.80 – 197.10
SFPUC	N/A	N/A	N/A	N/A	N/A
Black & Veatch	N/A	N/A	N/A	N/A	N/A
LPI	1,000,000	10	\$40M - \$60M	4.00 - 6.00	156.00 – 234.00
SFPUC	500,000	3.08	\$21M	5.25	N/A
Black & Veatch	N/A	N/A	N/A	N/A	N/A
LPI	300,000	3	\$15M - \$21M	5.00 - 7.00	195.00 - 273.00
SFPUC	300,000	2.77	\$29.7M	8.25	N/A
Black & Veatch	335,250	2.89	\$15.5M	4.16	154.39

[97] San Francisco Public Utilities Commission, Renewable Energy Assessment Final Report, 10 January 2014

[98] Black and Veatch figures are capital cost in 2013 dollars

LPI	300,000	3	$15M - $21M	5.00 - 7.00	195.00 - 273.00
SFPUC	233,600	2.16	$23.1M	8.25	N/A
Black & Veatch	233,600	2.0	$11.2M	4.29	168.09
LPI	N/A	N/A	N/A	N/A	N/A
SFPUC	255,380	2.36	$25.3M	8.25	N/A
Black & Veatch	255,380	2.65	$14.3M	4.16	$149.64
LPI	N/A	N/A	N/A	N/A	N/A
SFPUC	500,000	3.08	$21M	5.25	N/A
Black & Veatch	N/A	N/A	N/A	N/A	N/A

Table 12 Wind Estimated Cost Comparison[99]

2	29	2,738	60	0	82.011
30	15	2,577	35	0	129.85
6	20	2,820	35	0	104.33
100	31	2,043	35	2.66	56.13
20	34	2,349	35	2.68	56.63
170	34	2,244	35	2.70	54.89
100	37	2,649	35	2.62	56.85
100	34	2,332	35	2.68	56.34

Table 13 Estimated Geothermal Cost Comparison[100]

50	80	4,963	30	61.91
50	90	4,467	27	53.37

[99] San Francisco Public Utilities Commission, Renewable Energy Assessment Final Report, 10 January 2014, page 1-4

[100] San Francisco Public Utilities Commission, Renewable Energy Assessment Final Report, 10 January 2014, page 1-5

40	80	4,283	34	63.81

The SFPUC also surveyed potential sites for small hydro systems. The Draft Build-out Roadmap[101] identified University Mound[102], and the Hetch Hetchy system as potential sites for small hydro systems. In the case of Hetch Hetchy, one proposed approach would be to construct the small hydro systems inside of the water pipelines[103]. Some hydro projects have a potential beneficial capability to increase water supply, storage or reliability[104]. Further, the small hydro projects tend to be RPS-compliant unlike large hydro projects. However, some hydro projects might have a negative impact on water delivery. Hydro projects will not be constructed unless they have minimal or no negative impact on water delivery. Although no specific small hydro projects have been identified, Willdan estimates that small hydro projects would yield approximately 6.9 construction jobs and 0.24 ongoing operations jobs per $1 million in construction expenditures

6.1.1 Jobs Impact

Utilizing the National Renewable Energy Laboratory (NREL) Jobs and Economic Development Impact Models (JEDI)[105] tool[106], a high level estimate of jobs created for each of the projects listed can be developed. This comparison assumes a 2016[107] start date for construction and the definition of "local" in the model output would indicate broader regional and even state wide impacts rather than specifically within the City of San Francisco. The high analysis summarized in

[101] CleanPowerSF Build-Out Roadmap and Strategies, SFPUC Power Enterprise, June 2013, page 12

[102] CleanPowerSF Build-Out Roadmap and Strategies, SFPUC Power Enterprise, June 2013, page 12

[103] CleanPowerSF Build-Out Roadmap and Strategies, SFPUC Power Enterprise, June 2013, page 19

[104] Draft SFPUC Water & Power System, Hydroelectric Renewable and Clean Energy Generation Opportunities table, Long-term Renewable Plan (High Level Screening Only)

[105] National Renewable Energy Laboratory (NREL) Jobs and Economic Development Impact (JEDI) http://www.nrel.gov/analysis/jedi/

[106] NREL JEDI Notes: Earnings and Output values are millions of dollars in year 2014 dollars. Construction and operating jobs are full-time equivalent for a period of one year (1 FTE = 2,080 hours). Totals may not add up due to independent rounding. Results are based on User modifications to default values. This model uses similar methodology to that used by the Controller's Office, REMI, but may generate somewhat different results. If the Controller's office runs an analysis using REMI the results can be attached to this report.

[107] It is not realistic for all projects to be constructed in 2016. However, this provided a basis for economic impact assessment. Actual approval and construction schedules will have a significant affect both project costs and economic impact.

Table 15 through Table 23 is based upon the average capacity of the range shown in Table 11. However, this model output does provide an estimate of the magnitude of economic development associated with renewable energy projects of the types and sizes listed in Section 6.1. For each project the model estimated jobs created, earnings, and economic activity. Earnings are the wages and other compensation earned by workers, while economic activity (or output) is the sum of all activity that results from the construction of the project (including wages, buying and selling of goods, etc.). The assumptions listed in the tables can be refined for the specific projects as described in Section 2.1.2 to derive a detailed lower level economic analysis for San Francisco. For projects that have a range of estimated costs, the jobs estimate represents the midpoint of those figures.

PV Projects[108]

Table 14 Default Assumptions Built Into the NREL JEDI Tool for PV Systems

3.5%	100%	N
38.3%	100%	N
4.0%	100%	N
5.7%	100%	N
51.5%		
8.7%	100%	
8.7%		
60.2%		
0.4%	100%	
8.9%	100%	
26.2%	100%	
35.5%		
95.7%		
4.3%	100%	
100.0%		
58.1%	100%	
58.1%		
38.7%	100%	N
0.0%	100%	
38.7%		
3.2%	100%	
100.0%		

[108] The NREL JEDI Photovoltaics "*demonstration model is designed to estimate the statewide impacts associated with developing photovoltaic system for distributed generation capabilities. The economic impacts identified include annual jobs, earnings, and output for the installation period and once the systems are up and running.*"

Table 15 Warnerville Substation Local Economic Impacts - Summary Results

	$000 (2014)	**$000 (2014)**
213.2	$13,811.2	
219.6	$12,456.8	
432.8	***$26,268.1***	***$42,102***
0.0	$0.0	$0
46.6	$2,755	$8,024
0.0	$0	$0
31.6	$1,448	$4,300
82.9	$9,369	$26,377
186.0	$6,635	$12,097
347.1	***$20,207***	***$50,799***
191.7	$8,136	$24,340
971.6	***$54,611***	***$117,241***

Annual Jobs	**Annual Earnings $000 (2014)**	**Annual Output $000 (2014)**
5.5	$331	$331
1.5	$86	$273
1.0	$44	$132
8.1	***$462***	***$737***

Table 16 Sunol Valley Local Economic Impacts - Summary Results

	$000 (2014)	**$000 (2014)**
125.1	$8,100	
128.8	$7,306	
253.9	***$15,406***	***$24,693***
0.0	$0	$0
27.3	$1,616	$4,706
0.0	$0	$0
18.6	$850	$2,523
48.6	$5,495	$15,470
109.1	$3,891	$7,095
203.6	***$11,852***	***$29,794***
112.4	$4,772	$14,276
569.9	***$32,030***	***$68,763***

Annual Jobs	**Annual Earnings $000 (2014)**	**Annual Output $000 (2014)**
3.2	$194	$194
0.9	$51	$161
0.6	$26	$77
4.7	***$271***	***$432***

Table 17 Tesla Portal Local Economic Impacts - Summary Results

	$000 (2014)	**$000 (2014)**
45.0	$2,916	
46.4	$2,630	
91.4	***$5,546***	***$8,889***
0.0	$0	$0
9.8	$582	$1,694
0.0	$0	$0
6.7	$306	$908
17.5	$1,978	$5,569
39.3	$1,401	$2,554
73.3	***$4,267***	***$10,725***
40.5	$1,718	$5,139
205.1	**$11,529**	**$24,752**
Annual Jobs	**Annual Earnings $000 (2014)**	**Annual Output $000 (2014)**
1.5	$89	$899
0.4	$23	$73
0.3	$12	$35
2.2	**$124**	**$198**

Table 18 SFO Parking Lot Local Economic Impacts - Summary Results

	$000 (2014)	**$000 (2014)**
84.4	$5,467	
86.9	$4,931	
171.3	***$10,398***	***$16,666***
0.0	$0	$0
18.4	$1,091	$3,176
0.0	$0	$0
12.5	$573	$1,703
32.8	$3,709	$10,441
73.6	$2,626	$4,788
137.4	***$7,999***	***$20,108***
75.9	$3,221	$9,635
384.6	**$21,618**	**$46,409**

Annual Jobs	**Annual Earnings $000 (2014)**	**Annual Output $000 (2014)**
1.8	$111	$111
0.5	$29	$92
0.4	$15	$44
2.7	***$155***	***$247***

Table 19 Hunters Point - Parcel E - Local Economic Impacts - Summary Results

	$000 (2014)	**$000 (2014)**
46.5	$3,009	
47.8	$2,713	
94.3	***$5,722***	***$9,172***
0.0	$0	$0
10.1	$600	$1,748
0.0	$0	$0
6.9	$316	$937
18.1	$2,041	$5,746
40.5	$1,445	$2,635
75.6	***$4,402***	***$11,066***
41.8	$1,772	$5,302
211.7	**$11,897**	**$25,540**

Annual Jobs	**Annual Earnings $000 (2014)**	**Annual Output $000 (2014)**
1.2	$72	$72
0.3	$19	$60
0.2	$10	$29
1.8	**$101**	**$161**

Table 20 University Mound - North Basin - Local Economic Impacts - Summary Results

	$000 (2014)	$000 (2014)
24.7	$1,601	
25.5	$1,444	
50.2	***$3,046***	***$4,881***
0.0	$0	$0
5.4	$319	$930
0.0	$0	$0
3.7	$168	$499
9.6	$1,086	$3,058
21.6	$769	$1,403
40.2	***$2,343***	***$5,890***
22.2	$943	$2,822
112.7	**$6,332**	**$13,593**

Annual Jobs	Annual Earnings $000 (2014)	Annual Output $000 (2014)
0.5	$32	$32
0.1	$8	$26
0.1	$4	$13
0.8	**$45**	**$71**

Table 21 Sutro Reservoir / Summit Pump Station Local Economic Impacts - Summary Results

	$000 (2014)	$000 (2014)
20.6	$1,334	
21.2	$1,203	
41.8	***$2,537***	***$4,066***
0.0	$0	$0
4.5	$266	$775
0.0	$0	$0
3.1	$140	$415
8.0	$905	$2,547
18.0	$641	$1,168
33.5	***$1,952***	***$4,906***
18.5	$786	$2,351
93.8	**$5,274**	**$11,322**

Annual Jobs	Annual Earnings $000 (2014)	Annual Output $000 (2014)
0.4	$27	$27
0.1	$7	$22
0.1	$4	$11
0.6	**$37**	**$59**

Table 22 Pulgas Balancing Reservoir Local Economic Impacts - Summary Results

	$000 (2014)	**$000 (2014)**
21.8	$1,414	
22.5	$1,275	
44.3	***$2,689***	***$4,309***
0.0	$0	$0.0
4.8	$282	$821
0.0	$0	$0
3.2	$148	$440
8.5	$959	$2,670
19.0	$679	$1,238
35.5	***$2,068***	***$5,199***
19.6	$833	$2,491
99.4	**$5,589**	**$11,999**

Annual Jobs	**Annual Earnings $000 (2014)**	**Annual Output $000 (2014)**
0.5	$28	$28
0.1	$7	$23
0.1	$4	$11
0.7	**$39**	**$62**

Table 23 SF Port- pier 90-94 Local Economic Impacts - Summary Results

		$000 (2014)	$000 (2014)
	22.7	$1,473	
	23.4	$1,329	
	46.2	***$2,802***	***$4,492***
	0.0	$0	$0
	5.0	$294	$856
	0.0	$0	$0
	3.4	$155	$459
	8.8	$1,000	$2,814
	19.8	$708	$1,291
	37.0	***$2,156***	***$5,419***
	20.4	$868	$2,597
	103.7	**$5,826**	**$12,507**

	Annual Jobs	Annual Earnings $000 (2014)	Annual Output $000 (2014)
	0.6	$34	$34
	0.2	$9	$28
	0.1	$5	$14
	0.8	**$48**	**$76**

Table 24 Solar Project Economic Impact Summary

Low	Avg.	High	Low	Avg.	High	Jobs per $Million	Low	Avg.	High	Jobs per $Million	Low	Avg.	High
25	29.8	35	$140	$173	$210	5.6	788	972	1182	0.05	6.6	8.1	9.9
13.4	17.5	20	$50	$85	$120	6.7	336	570	806	0.06	2.8	4.7	6.6
1.6	2.8	5	$6	$17	$30	12.2	67.2	205	367	0.13	0.7	2.2	3.9
10	10.0	10	$50	$60	$70	6.4	321	385	449	0.05	2.3	2.7	3.2
3	6.5	10	$21	$40	$60	5.3	110	212	315	0.04	0.9	1.8	2.7
3	2.9	3	$15	$20	$30	5.6	83.5	113	167	0.04	0.6	0.8	1.2

2	2.4	3	$11	$18	$23	5.3	58.8	94	123	0.03	0.4	0.6	0.8
2.5	2.5	2.5	$14	$20	$25	5.0	70	99	125	0.04	0.5	0.7	0.9
3.1	3.1	3.1	$21	$21	$21	5.0	104	104	104	0.03	0.6	0.6	0.6

Wind Projects[109]

Table 25 Default Assumptions Built Into the NREL JEDI Tool for Wind Systems

39.3%	0%
9.2%	0%
10.2%	0%
7.0%	0%
65.7%	
9.5%	90%
1.1%	0%
1.1%	100%
2.1%	70%
13.8%	
1.9%	95%
2.1%	75%
3.1%	70%
1.6%	0%
3.6%	50%
12.2%	
0.7%	90%
0.2%	10%
0.9%	0%
0.5%	100%
0.0%	100%
0.2%	100%
2.4%	
28.4%	

[109] The NREL JEDI Wind "*model is designed to estimate the statewide economic impacts associated with developing and operating wind power generation facilities in the United States. The economic impacts identified include jobs, earnings, and output from the construction period and annually once the windfarm is up and running*" Wind farm workers include field technicians, administration and management. Economic impacts "During operating years" represent impacts that occur from wind farm operations/expenditures. The analysis does not include impacts associated with spending of wind farm "profits" and assumes no tax abatement unless noted.

94.1%	
5.9%	***100%***
100.0%	
12.5%	100%
1.4%	100%
5.9%	100%
19.8%	
2.2%	100%
0.8%	80%
0.4%	100%
1.7%	100%
16.2%	0%
0.8%	100%
5.5%	100%
48.0%	2%
75.6%	
4.6%	100%
0.0%	100%
100.0%	

Table 26 Oceanside Wind Local Economic Impacts - Summary Results

4	$0.3	
0	$0.0	
4	***$0.3***	***$0.3***
7	$0.5	$1.4
5	$0.3	$0.8
16	**$1.1**	**$2.5**
0	$0.0	$0.0
0	$0.0	$0.1
0	$0.0	$0.0
1	**$0.0**	**$0.1**

Table 27 Sunol Local Economic Impacts - Summary Results

42	$3.1	
2	$0.2	
45	***$3.3***	***$3.5***
99	$7.3	$19.2
63	$4.1	$11.3
207	**$14.7**	**$34.0**
3	$0.2	$0.2
2	$0.2	$0.6
1	$0.1	$0.2
7	**$0.5**	**$1.0**

Table 28 Tesla Local Economic Impacts - Summary Results

12	$0.8	
1	$0.1	
12	***$0.9***	***$0.9***
22	$1.6	$4.2
14	$0.9	$2.5
48	**$3.4**	**$7.7**
0	$0.0	$0.0
0	$0.0	$0.1
0	$0.0	$0.0
1	**$0.1**	**$0.2**

Table 29 Montezuma Hills Local Economic Impacts - Summary Results

60	$4.4	
7	$0.7	
67	***$5.0***	***$5.5***
259	$19.0	$50.0
159	$10.3	$28.7
485	**$34.4**	**$84.2**
6	$0.5	$0.5
7	$0.5	$1.7
4	$0.3	$0.7
17	**$1.2**	**$2.9**

Table 30 Altamont Pass Local Economic Impacts - Summary Results

39	$2.8	
1	$0.1	
40	***$2.9***	***$3.1***
61	$4.5	$11.8
40	$2.6	$7.2
141	**$10.0**	**$22.0**
2	$0.1	$0.1
2	$0.1	$0.4
1	$0.1	$0.2
4	**$0.3**	**$0.7**

Table 31 Walnut Grove Local Economic Impacts - Summary Results

85	$6.2	
13	$1.2	
98	***$7.5***	***$8.4***
482	$35.5	$93.1
294	$19.0	$52.9
873	**$61.9**	**$154.4**

9	$0.7	$0.7
12	$0.8	$2.8
6	$0.4	$1.2
28	**$2.0**	**$4.7**

Table 32 Leona Valley Local Economic Impacts - Summary Results

60	$4.4	
9	$0.9	
69	**$5.2**	**$5.9**
335	$24.6	$64.6
204	$13.2	$36.8
607	**$43.1**	**$107.3**

6	$0.5	$0.5
7	$0.5	$1.7
4	$0.3	$0.7
17	**$1.2**	**$2.9**

Table 33 Newberry Springs Local Economic Impacts - Summary Results

	60	$4.4	
	8	$0.8	
	68	**$5.1**	**$5.7**
	295	$21.7	$57.0
	181	$11.7	$32.5
	543	**$38.5**	**$95.2**
	6	$0.5	$0.5
	7	$0.5	$1.7
	4	$0.3	$0.7
	17	**$1.2**	**$2.9**

Geothermal Projects[110]

Table 34 Default Assumptions Built Into the NREL JEDI Tool for Geothermal Systems

	0.0%	0.0%	75%
	0.1%	0.1%	75%
	0.0%	0.0%	0%
	0.3%	0.2%	0%
	0.0%	0.0%	100%
	0.0%	0.0%	100%
	0.0%	0.0%	100%
	0.0%	0.0%	100%
	0.0%	0.0%	100%
	0.0%	0.0%	100%
	0.4%	0.3%	100%
	0.8%	**0.7%**	

[110] The NREL JEDI Geothermal "*model is designed to estimate the economic impacts of developing geothermal electric generation facilities. The economic impacts identified include annual jobs, earnings, and output for the construction period and once the plant is up and running*"

0.0%	0.0%	100%
0.0%	0.0%	100%
0.2%	0.1%	100%
0.0%	0.0%	100%
0.1%	0.1%	100%
0.0%	0.0%	100%
0.4%	0.3%	100%
0.1%	0.1%	100%
0.0%	0.0%	0%
0.1%	0.1%	100%
0.7%	0.5%	100%
0.1%	0.1%	0%
0.2%	0.1%	0%
0.2%	0.1%	100%
0.0%	0.0%	100%
0.1%	0.1%	100%
0.0%	0.0%	100%
0.0%	0.0%	0%
2.2%	**1.7%**	

0.2%	0.4%	100%
0.2%	0.4%	100%
1.9%	3.3%	100%
0.5%	0.9%	100%
1.5%	2.6%	100%
0.5%	0.9%	100%
4.7%	8.3%	100%
		100%
0.0%	0.1%	0%
1.0%	1.7%	100%
7.7%	13.6%	100%
1.0%	1.7%	0%
1.8%	3.1%	0%
2.0%	3.5%	100%
0.4%	0.7%	100%
1.0%	1.7%	100%
0.2%	0.3%	100%
7.8%	13.9%	0%
32.3%	**57.2%**	

Table 35 Default Assumptions Built Into the NREL JEDI Tool for Geothermal Flash Plant[111] - Power Plant Costs

0.6%	100%
1.1%	100%
1.1%	100%
1.1%	100%
1.7%	0%
5.7%	
20.6%	0%
0.7%	100%
3.1%	100%
3.6%	100%
1.6%	100%
0.1%	100%
0.3%	100%
30.0%	
95.2%	
4.8%	
100.0%	

[111] Geothermal Flash Power Plant uses geothermally heated water under pressure that is separated in a surface vessel (called a steam separator) into steam and hot water or "brine". The steam is delivered to the turbine, and the turbine powers a generator. The liquid is injected back into the reservoir.

Percent of Cost	Local Share
5.7%	100%
41.3%	100%
47.0%	
53.0%	0%
0.0%	0%
0.0%	0%
0.0%	0%
0.0%	0%
0.0%	0%
53.0%	
0.0%	0%
0.0%	0%
0.0%	0%
0.0%	0%
0.0%	0%
0.0%	
100.0%	

Table 36 Default Assumptions Built Into the NREL JEDI Tool for Geothermal Binary Plant[112] - Power Plant Costs

1.0%	100%
1.9%	100%
1.9%	100%
1.9%	100%

[112] Binary Geothermal Power Plant produces electricity from geothermal resources lower than 150°C (302°F). The geothermal water heats another liquid, such as isobutane which boils at a lower temperature than water. The two liquids are kept completely separate through the use of a heat exchanger, which transfers the heat energy from the geothermal water to the working fluid. The secondary fluid expands into gaseous vapor. The force of the expanding vapor, like steam, turns the turbines that power the generators. All of the produced geothermal water is injected back into the reservoir.

2.9%	0%
9.6%	
25.6%	0%
19.0%	100%
1.9%	100%
3.9%	100%
50.3%	
59.9%	
95.2%	
4.8%	
100.0%	
5.5%	100%
45.0%	100%
50.5%	
49.5%	0%
0.0%	0%
0.0%	0%
0.0%	0%
0.0%	0%
0.0%	0%
49.5%	
58.5%	0%
0.0%	0%
0.0%	0%
0.0%	0%
0.0%	0%
0.0%	
94.5%	
5.5%	
100.0%	

Table 37 Brawley - Binary - Local Economic Impacts - Summary Results

98	$7	$10
85	$5	
13	$1	
117	$10	$35
76	$4	$12
291	**$21**	**$57**
8	$1	$1
2	$0	$1
3	$0	$0
13	**$1**	**$3**

Table 38 Geysers - Flash - Local Economic Impacts - Summary Results

139	$10	$15
122	$9	
18	$2	
149	$12	$45
101	$6	$16
389	**$28**	**$76**
9	$1	$1
2	$0	$2
3	$0	$1
14	**$2**	**$4**

Table 39 Long Valley – Binary - Local Economic Impacts - Summary Results

609	$38	$57
551	$33	
58	$5	
750	$62	$226
472	$27	$76
1,830	**$127**	**$358**

24	$3	$3
6	$0	$5
9	$1	$2
39	**$4**	**$10**

Table 40 Wind and Geothermal Project Economic Impact[113]

Oceanside	2	$2,738	0.01	16	0.0004	1
Sunol	30	$2,577	0.08	207	0.0027	7
Tesla	6	$2,820	0.02	48	0.0004	1
MontezumaHills	100	$2,043	0.24	485	0.0083	17
AltamontPass	20	$2,349	0.06	141	0.0017	4
WalnutGrove	170	$2,244	0.39	873	0.0125	28
LeonaValley	100	$2,649	0.23	607	0.0064	17
NewberrySprings	100	$2,332	0.23	543	0.0073	17
	528	$19,752	0.15	2920	0.0047	92
Brawley-Binary	50	$4,963	0.06	291	0.0026	13
Geysers-Flash	50	$4,467	0.09	389	0.0031	14
LongValley–Binary	40	$4,283	0.43	1830	0.0091	39
	140	$13,713	0.18	2510	0.0048	66

[113] Details for the possible Wind and Geothermal projects are described in Section 6.1

Table 41 Build-out Project Economic Impact Summary (Assuming ALL Projects are Constructed)

64	78	92	$328	$453	$589	5.0	6.3	12.2	1,939	2,754	3,638	0.03	0.04	0.05	15	22	30
	528			$19,752			0.15			2,920			0.005			92	
	140			$13,713			0.18			2,510			0.005			66	

114 Variance in capacity, cost and economic impact for solar project estimates due to up to three project assessments with a variety of capacity specifications and cost possibilities

6.2 Evaluate Small Hydro Investments

This section evaluates the potential for CPSF to invest in small hydroelectric power programs to develop an analysis of economic benefits for CPSF and its ratepayers.

Provided there is no negative impact on water delivery, small hydro projects are a viable renewable generation technology that should be considered along with solar, wind and geothermal projects. Preliminary data indicates that some small hydro projects have some of the lowest costs of all the renewable projects considered.

Some LCOE data was present in the material furnished by the SFPUC and is included below. Preliminary high level screening of small hydro projects indicate that there is potential to generate energy through small hydro projects. The following material furnished by the SFPUC summarizes small hydro opportunities on SFPUC's water system.

6.2.1 Small Hydro Opportunities on the SFPUC's Water System

Opportunities for development of small or qualifying renewable hydro[115] generation on the SFPUC water system are best understood when considered in two distinct geographical areas. One geographical area of the water system is the greater San Francisco Bay Area region, which includes San Francisco, the Peninsula, Bay Division pipelines, and the Sunol Valley Region. The other geographic area is San Joaquin / Upcountry which lies outside of the greater Bay Area and includes the upcountry Hetchy Hetch hydroelectric system of major storage reservoirs and hydroelectric generation plants all located in the Sierras, and the water transmission system of tunnels and pipelines that cross the San Joaquin Valley to deliver Hetch Hetchy water to the Bay Area.

In general, most new hydro generation opportunities on the SFPUC's water system are located outside of the greater Bay Area on the San Joaquin/Upcountry portion of the water system. Owing to the efficient design of the existing SFPUC Hetch Hetchy water system, and the efficient extraction of this renewable energy upcountry by way of the existing hydroelectric plants, there is not much additional hydroelectric generation potential in the in the greater Bay Area. In both San Francisco and in the Sunol Region, the SFPUC has already begun development of two new hydro projects. These two projects – University Mound (240 kW) and Sunol (1000 kW or 1 MW) – are actively under development and comprise plants that can capture excess energy in the water flowing within the water system.

While other potential San Francisco Bay Area region sites and opportunities have been studied, including but not limited to Merced Manor reservoir inlet (100 kW), Hunter's Point inlet (37 kW)

[115] RPS eligible small hydroelectric systems include: 1) small hydro facilities 30 MW or less; 2) conduit hydroelectric facilities 30 MW or less; 3) existing hydroelectric generation units 40 MW or less and operated as part of a water supply or conveyance system; and 4) incremental generation from eligible efficiency improvements to hydroelectric facilities, regardless of the facility's overall generating capacity.

and Potrero Heights inlet (8 kW), the University Mound and Sunol projects were considered the most practical for near-term development. Assuming a capital cost of $6 million and financing cost of 4%, we estimate the University Mound project will have a levelized cost of energy of about 25c/kWh for the first 25 years of operation; however, the power cost from the project could be less than 4c/kWh for the balance of the plant life of 25 years or longer. The Sunol located plant has more favorable economics[116]. With an assumed $7 million capital cost and financing cost of 4%, the Sunol project would have a levelized cost of energy of 7c/kWh for the first 25 years, and about 1c/kWh for operation thereafter[117]. In order to compare the levelized cost of the hydro projects to the LCOE costs for the other types of renewable energy, it will be necessary to calculate a single LCOE cost that applies to the entire duration of the project.

Additional San Francisco Bay Area region hydro resources suitable for development likely exist, but while these potential projects need to be explored further, it is anticipated that there is probably a total potential of no greater than 10 MW at best, and more likely an amount closer to 5 MW[118]. Additional analysis is required to estimate the cost of these projects.

The SFPUC has recognized that an equally important energy opportunity related to the movement of water within the SFPUC system in the Bay Area is in energy efficiency and load shifting that could free up additional Hetch Hetchy hydro supplies for other SFPUC power supply purposes. All of the SFPUC's major pumping operations occur within the SFPUC's Bay Area regional water system and while the system is already efficiently configured, the SFPUC continually analyzes its pumping operations to minimize pumping energy consumption. Pumping system optimization can smooth out electric consumption associated with the water supply system to minimize peak demand and shift usage to off peak hours. The SFPUC's commitment to managing and improving the energy efficiency of its water supply system has the potential to free up capacity and energy from the Hetch Hetchy system for other beneficial purposes.

On the San Joaquin/Upcountry portion of SFPUC water system located outside of the Bay Area some conventional renewable small hydro plants and efficiency improvements have been envisioned, that might total about 10 MW of additional installed capacity[119].

Further review of the system's renewable hydro generation potential is warranted, however. Additional projects in the upcountry Region including Moccasin and East of Moccasin could include system efficiency improvements to yield more capacity and energy, as well as new capital developments. If the power generation need existed to further develop these new hydro

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[116] Small Hydro Opportunities on the SFPUC Water System, September 18, 2014, provided by the SF PUC

[117] Small Hydro Opportunities on the SFPUC Water System, September 18, 2014, provided by the SF PUC

[118] Small Hydro Opportunities on the SFPUC Water System, September 18, 2014, provided by the SF PUC

[119] Small Hydro Opportunities on the SFPUC Water System, September 18, 2014, provided by the SF PUC

capacity opportunities the total development potential might be greater than 50 MW[120]. However, the economics and permitting issues associated with these developments would need to be carefully analyzed.

Regardless of the potential capacity and energy available from Hetch Hetchy efficiency improvements and new small hydro plants, a policy decision would be needed from the SFPUC as to whether this energy should be used for CPSF, or, would have a higher value for other new SFPUC power loads such as TransBay terminal and Hunter's Point. It is to be noted that the Sunol hydro plant is being financed by the Water Department. The Water Department expects to gain energy and economic benefits from deployment of the small 1 MW hydro plant on their water system[121]. If the CPSF becomes a customer for excess power from SFPUC hydro projects, then it would be worthwhile to further investigate which hydro projects are cost effective in terms of LCOE's.

6.2.2 Assessment of Small Hydro Projects

As was done with the other renewable project sites, LCOE costs should be calculated for small hydro projects at the University Mound and Hetch Hetchy sites. An ONRL report[122] includes a description of cost methodology which can be used to calculate the LCOE's for small hydro sites.

Benefits of small hydro projects include potentially qualifying as renewable energy under the California Renewable Portfolio Standards (RPS)[123], competitive costs compared with other renewables, and LCOEs largely dependent on Initial Capital Cost (ICC)[124], which could work to the City's advantage if it has access to low cost capital. It should be noted that the current focus on the Water System Improvement Project and recent Hetch Hetchy system electrical reliability compliance and tunnel infrastructure maintenance has limited the ability of SFPUC personnel to move these small hydro projects forward as these more urgent system improvement and maintenance matters are taking precedent. Additional staff can and should be added to the Water Department and if necessary to other organizations within the SFPUC in order to develop small hydro projects. Doing so would help meet the City's goals to increase the supply of cost-

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[120] Small Hydro Opportunities on the SFPUC Water System, September 18, 2014, provided by the SF PUC

[121121]Small Hydro Opportunities on the SFPUC Water System, September 18, 2014, provided by the SF PUC

[122] Small Hydropower Cost Reference Model, October 2012, ORNL/TM-2012/501: http://info.ornl.gov/sites/publications/files/pub39663.pdf

[123] California Energy Commission Renewables Portfolio Standard Eligibility Seventh Edition Staff Draft Guidebook, March 2013: http://www.energy.ca.gov/2013publications/CEC-300-2013-005/CEC-300-2013-005-ED7-SD.pdf Note that Hetch Hetchy as a large hydroelectric generation station does not qualify as a California RPS resource although it is renewable and carbon emission free.

[124] Small Hydropower Cost Reference Model, October 2012, ORNL/TM-2012/501, page 37: http://info.ornl.gov/sites/publications/files/pub39663.pdf

effective renewable energy, to add local jobs and to become a leader in innovative green energy projects.

After determining LCOE's for at least some of the identified small hydro sites, it would be appropriate to consider issuing an RFI and perhaps an RFP to identify potential small hydro developers. The process to do so would be similar as is described for the Sunol RFI and RFP in the next section.

6.2.3 Jobs Impact

The NREL JEDI tool has modules for both conventional hydroelectric generation dams as well as new models for marine based hydroelectric generation, but does not yet have a model for assessing economic impact for small in-line hydroelectric projects. Willdan has adapted the model and provided an estimate of jobs created per $1 million in expenditures above in Section 2.1.2. with an extract in Table 42 below

Table 42 Small Hydro Economic Impact

	6.3	Yes	Possible with local procurement req.	Positive
	6.7	Minor	Regional	Regional
	6.9	None Significant	None Significant	None Significant
Varies		None	None	None

Table 43 Small Hydro Economic Impact

0.19	0
0.57	0
0.95	0
1.33	0
1.71	0

6.3 Evaluate Potential for Sunol Solar Project

Per the SFPUC Draft Build-out Roadmap and Strategies[125], the CPSF is investigating sites that might be attractive for construction of privately owned projects, building on the information provided by the existing analysis of individual projects. The SFPUC will continue to identify prospects for City-owned projects and privately-owned projects on City property. One such site under consideration is Sunol, California which is being considered for a solar project and which was also evaluated as a potential site for wind projects. Estimated costs for the Sunol solar project differ significantly (see Table 11 with cost estimates varying from $47.9M - $120M). Additional analysis of cost estimates for the Sunol project are thus advised to verify its economic viability.

CPSF is considering a solar PV installation on an approximately 100 acre site in Sunol on land which is owned by the City. As part of strategy 5, the Draft Roadmap[126] recommends that an RFP be developed for a cost effective solar project in Sunol which is located approximately 40 miles southeast of the City. As shown in Table 11 above, Sunol has the lowest levelized cost for solar projects near San Francisco.

An RFP which seeks to purchase local power from projects in Sunol and other local areas is an effective method to identify cost-effective renewable energy projects. Cost estimates developed in the SFPUC Renewable Energy Assessment Final Report[127] indicate a LCOE of $80.48 per MWh, not including the costs to transmit the energy to the City. As stated in the Final Report, the actual cost paid by the City will depend on market factors.

6.3.1 Plan for Sunol RFP

Estimated costs for the Sunol solar project differ significantly. If additional analysis of the cost estimates for Sunol validate that it is the lowest cost solar project, the next step is to verify that Sunol is the lowest cost option among all renewable energy projects.

In order to validate that a Sunol solar project is the most cost-effective option among all renewable projects, the recommended process is to first issue a Request for Information (RFI) to prospective Sunol project developers as well as to other potential local power providers. The RFI would indicate that CPSF proposes to enter into multiple year contracts to procure renewable energy and/or to develop renewable energy projects in local areas, including Sunol. The RFI would indicate CPSF is also interested in acquiring renewable energy from other cost effective local sources.

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[125] CleanPowerSF Build-Out Roadmap and Strategies, SFPUC Power Enterprise, June 2013

[126] CleanPowerSF Build-Out Roadmap and Strategies, SFPUC Power Enterprise, June 2013, page 12-13

[127] SFPUC Renewable Energy Assessment Final Report, 10 January 2014, page 1-3.

The RFI would invite potential providers to respond with questions and recommendations for the subsequent Request for Proposal (RFP). Based on inputs to the RFI, an RFP for renewable projects to include solar projects at Sunol would be issued. Based on the RFP responses, the most cost effective renewable energy projects can be readily identified by comparing LCOEs for the proposed projects.

6.3.2 Future Steps for Sunol Solar Project

For Sunol, and in general to locate renewable energy projects which are cost effective, the next steps would be to:

1. Consider ownership options. Determine if CPSF will own renewable energy projects at sites such as Sunol, or will allow developers to build privately-owned solar projects at sites to include Sunol. Another option would be to use PPA's to purchase renewable power from local sources. PPA's would require the CPSF to commit to long term contracts, but PPA's would not require capital investment. Please see more information on ownership options in Section 10.
2. Determine how much energy CPSF customers will require on an hourly basis (8760 hourly demand) throughout the year and then determine the amount of renewable energy which the CPSF needs to purchase to meet the desired percentage of renewable energy in its energy profile.
3. Determine which entity(ies) will be responsible for related power procurement services to include:
    a. CAISO Ancillary Services
    b. Scheduling Coordination
    c. Energy Shaping
    d. System Resource Adequacy
    e. Local Resource Adequacy
    f. Managing Distribution Losses

Based on the desired renewable energy project characteristics derived from the above steps, an RFP can be issued for Sunol and for other potentially cost-effective renewable energy projects.

6.4 Investigate Ratemaking Policies

This subtask investigated the prospects for petitioning the CPUC to change the ratemaking policy that requires CCA customers to pay for transmission services that they do not use.

As background information, the transmission and distribution systems deliver electricity from generation sites to electricity end users. As shown below in Figure 9, the dashed yellow line shows the flow of electricity from generation through the transmission and distribution systems to consumers, which includes CCA customers. For local build out projects which connect to the distribution system, the CCA should not be charged for transmission services, as use of the transmission system will not be needed.

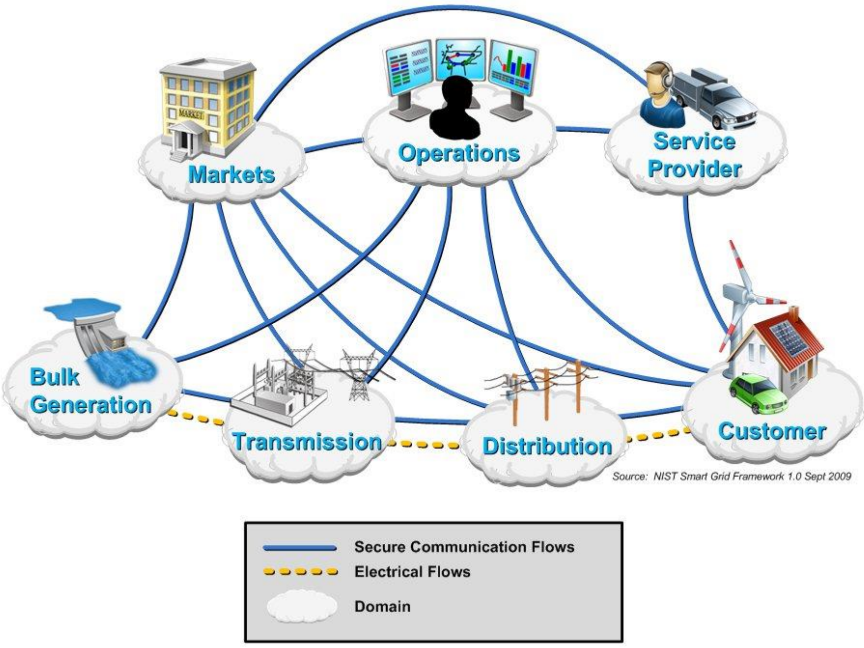

Figure 9: The Distribution and Transmission Systems deliver Electricity to Consumers including CCA Customers

Although it might seem that a CCA with local generation resources would not require the services of the transmission system, the CCA will need the services of the transmission system.

For example, the CPSF would use the transmission system to move energy from sites such as Sunol. The energy generated at Sunol would pass through the transmission system on its way to the City. The delivered power would incur an appropriate wheeling charge as assessed by CAISO to cover the cost of using the transmission system.

Additionally, the real time balancing of electricity supply and demand is performed by CAISO. The generation resources utilized by CAISO to ensure demand is met with generation are dispatched based on their bid price and proximity to the load. Therefore, CAISO transmission will be required in order to deliver electricity between CAISO participating generation resources and CPSF customers in real time. Note that CAISO is paid for transmission delivery services while PG&E is paid for distribution delivery services.

The California Public Utility Commission (CPUC) can be petitioned for changes on behalf of the CPSF to ensure that transmission charges reflect an appropriate amount of transmission system utilization; however, the CPSF will need to pay the fair cost of services it receives.

6.5 Conclusions: Renewable Energy Projects including Jobs Created Summary

1) Existing cost estimates vary significantly for the many of the proposed renewable energy projects. Thus prior to build out, further analysis is necessary to validate the estimated cost of specific renewable energy projects. Review of existing, albeit varying cost estimates, indicates that build out of small hydro projects by the City's Water Department as well as PPAs to acquire solar and wind energy from local and regional projects are the most cost effective sources of renewable energy. For solar projects, transfer of ownership to CPSF after several years appears to be the most cost effective option. Ownership transfer of solar projects is also recommended, as it will lower risk for the CPSF.
2) The small hydroelectric generation projects being considered by SFPUC include a variety of projects for alterations or improvements to existing hydroelectric generation as well as water supply and delivery. As a result, the estimated economic impact related to the small hydro projects that would need to be further refined as each project is considered for approval and implementation.
3) The jobs impacts of the projects vary between two and seven jobs created per $1 million in construction, with most projects creating between six and seven jobs per $1 million and wind projects just above two jobs per $1 million. Projects also create less than one job during operation for each $1 million in construction costs. The location of the jobs essentially follows the location of the project, so projects within San Francisco will generally create local jobs while projects within the region will generally create regional jobs. A key to the economic impact analysis of the projects is their location, projects in SF and in the region will generate jobs that benefit SF and the region while projects further afield will not.

7 TASK 7: BEHIND-THE-METER DEPLOYMENT STRATEGIES

As stated in the SFPUC's Electricity Resource Plan[128]: "An advantage of these local, behind-the meter activities is that they promote local economic development and job creation." Further, many behind-the-meter projects could also save customers money by reducing their overall energy costs.

[128] San Francisco's 2011 Updated Electricity Resource Plan, March 2011, page 7

7.1 BTM Feasibility Analysis

Behind the meter (BTM) projects include distributed generation, energy storage and demand side management programs. CPSF could offer subsidies and rebates that would incentivize CCA customers to install BTM projects similar to the way rebates and tax credits encourage installation of solar and wind projects. Bonds may be used to support BTM projects, and it is important to understand how BTM projects are currently financed in order to offer programs that will appeal to prospective BTM system owners.

BTM projects are typically funded by the systems' owners, often with third party financing, supplemented with rebates or tax credits. Another popular option is for systems to be owned and maintained by third parties such as Solar City who then lease the system to the building owners. Manufacturers of BTM systems such as Bloom Energy sometime offer financing programs through banks. CPSF can also offer to buy excess power from customer's BTM systems.

In addition to funding BTM projects, another possibility would be for CPSF to purchase excess BTM power generation. One option would be to buy power from generation system owners during off-peak times including weekends and nights. Systems such as fuel cells work best at a steady level of output, thus forcing owners to either run them at a low minimum level or to find a use for the excess energy. Another option would be to encourage installation of energy storage systems as CCAs now have an energy storage procurement requirement of 1% of peak demand, per CPUC Decision 13-10-040[129].

Demand Response as an aspect of DSM was discussed in 5.3.1. DR resources essentially compensate customer to reduce demand rather than procuring an incremental amount of generation. When energy prices are high, paying a customer to reduce load can be cost effective in comparison with the next least cost generation resource available. However, DR resources are "limited use" with customers willing to participate in occasional events to help keep electricity costs down and ensure reliability. Therefore, DR should not be considered a resource that can be utilized on a regular basis and instead should be viewed as a mitigation resource when generation prices are high or as a contingent resource when an expected generation source or transmission/distribution infrastructure component goes offline.

In order to increase investment in BTM projects, CPSF will need to offer programs that are economically beneficial to the system owners while at the same time have a neutral to positive impact on the overall economics of CPSF's program. Thus a financial analysis is needed which determines costs for both the CPSF and the BTM owners. The financial analysis will need to consider funding mechanisms and alternatives to CPSF-funded BTM projects. Currently residential property and building owners have options for pursuing BTM projects including:

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[129] CPUC Decision D1310040 Adopting Energy Storage Procurement Framework and Design Program, October 21, 2013: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M079/K533/79533378.PDF

owning and paying the full cost of BTM projects; leasing the systems; paying a monthly fee for BTM services including demand side management; or receiving cost savings in return for allowing the BTM systems to be installed on their premises. Please see Section 10 for more information on financing options.

The financial analysis needs to consider how costs and benefits will be split between the CPSF and the owners. Owners, utilities and third parties currently offer assistance with BTM projects including solar systems, energy storage and demand side management (DSM) programs such as programmable thermostats. Please see Section 10 for an analysis of how financing option impact costs. As stated in the SPFUC Review of the Local Power Inc. Draft Financial Deliverable, “shared savings” agreements with customers would be realistic, while assuming that all economic benefits would accrue to CPSF would not be[130].

Steps needed to complete the feasibility analysis are:

1) Identify BTM projects which have demonstrated viability which include:
    a. Energy storage systems which can provide energy to CPSF and ancillary services (AS) in the CAISO market
    b. Demand Side Management systems including Demand Response, Building Management Systems for commercial properties and Energy Management Systems for residences
    c. Solar systems which are also discussed in Section 8.
2) Perform market segmentation study that identifies commercial, business and residential customer segments and customer interests/drivers for each.
3) Create Use Cases for the above BTM systems and customer segments which specify how the CPSF programs and any related dispatch or control systems will interact with the BTM systems. In addition, the Use Cases need to identify how BTM systems will impact CPSF’s load scheduling requirements. Specifically the use cases need to clarify how energy exported to the grid from customer sited BTM resources will be accounted for in CPSF’s hourly load obligation for scheduling purposes.
4) Develop business cases for the BTM systems. Assess the costs and benefits of BTM systems including the economic value of energy exported to the grid from customer sited BTM resources. Identify cost effective BTM systems for commercial, business and residential customer segments. It is likely that the results from the business cases will indicate that the CPSF should fund rebates or subsidies for BTM projects rather than participate in BTM project development, ownership or operation.

[130] SPFUC Review of the Local Power Inc. Draft Financial Deliverable, November 30, 2012, page 3

5) Evaluate financing options for viable technologies applicable to commercial, business and residential customer segments as described in Section 10.
6) Identify third party suppliers and installers for cost effective BTM systems for commercial, business and residential customer segments.
7) Develop a BTM Implementation Plan which includes:
    a. Develop a BTM strategy and policy statement for CPSF, clearly identifying the BTM technologies and economics that have economic benefits to owners and neutral to positive revenue benefits to CPSF.
    b. Identify bond and commercial funding sources
    c. Define CPSF BTM staff organization and roles
    d. Specify a BTM marketing and outreach program for commercial, business and residential customer segments.
    e. Develop an education and training program for BTM installers, inspectors and educators
    f. State how the economic benefits identified in Step a will be calculated and verified
8) Issue an RFI for BTM suppliers
9) Based on RFI responses, issue RFPs to the third parties identified in step 6) above.

It should be noted that BTM projects will likely reduce the net load served by CPSF. Therefore, fewer MWh will be sold to end use customers. This will result in less energy and capacity procurement requirements but will also reduce the total revenue received through CPSF electricity sales under the rate programs previously considered. There may be an opportunity to develop different rate structures that could incent economic BTM technology deployment while having neutral to positive economic benefits to CPSF. We recommend that CPSF further investigate BTM projects, particularly Demand Response and Demand Side Management programs, to help mitigate the high percentage of intermittent renewable resources desired in the power supply portfolio.

7.2 Three Year Financial Plan

The amount of CPSF funding devoted to BTM programs will need to be determined after the overall budget is determined and the BTM financial analysis is complete. In order to determine funding amounts, business cases for BTM projects need to be developed. Projects and methods that show a positive return on investment (ROI) for both CPSF customers and CPSF should be pursued. The recommended allocation of funds to BTM projects would be based on a return of investment hurdle of a specified number of years. Typically, depending on available funding and the cost of capital, projects are funded with an ROI of 6 or 7 years or less.

7.3 BTM Installation Planning

Similar to Section 2.3.3 and the project life cycle approach outlined in Figure 7, approval for CPSF implementation with an expected schedule is needed to develop a recommended plan for rolling out BTM programs. Installing BTM projects will generate opportunities for additional jobs primarily for the sales and installation of BTM equipment and subsequent maintenance and customer service and support for the equipment. The BTM Implementation Plan will need to highlight the necessary education, training, marketing and outreach steps for BTM installations in order to engage customers.

7.4 Attracting Customers through BTM Subsidies

As stated in the CPSF Draft Build-Out Roadmap and Strategies, BTM projects may induce SF businesses and residents to become CPSF customers due to the appeal of lower costs from BTM projects[131].

In general cost subsidies are an effective method to increase the use of new technology without requiring the CPSF to actively develop or manage the projects. Thus we believe that the business cases will likely indicate that rebates or subsidies for BTM projects are more cost effective than BTM project development, ownership or operation.

Economic benefits of potential BTM projects need to be calculated as described in the BTM Implementation Plan described in Section 7.1 above. For BTM projects that have positive benefits for both the system's owners and CPSF, incentives can and should be offered by the CCA. Incentives will help provide product differentiation and choices for CPSF customers, thus properly marketed BTM incentives will likely attract customers to the CCA. Program design and incentive levels create a range of possible economic impact (see Figure 10).

Examples of incentivized BTM projects that would be likely to induce businesses to consider joining the CCA include:

1) Energy storage systems which can provide energy to CPSF and ancillary services (AS) in the CAISO market
2) Demand Side Management systems including Building Management Systems for commercial properties and Energy Management Systems for residences
3) Solar systems which are also discussed in section 8.

For residential customers, Energy Management Systems (ESM) are being integrated with home automation systems which typically control a home's thermostat, reduce costs for both residents and energy service providers. Customer migration towards these technologies is

[131] CleanPowerSF Build-Out Roadmap and Strategies Draft, SFPUC Power Enterprise, June 2013, page 13

illustrated by the popularity of the Nest thermostat.[132] These individual customer devices begin to connect "the Internet of things" to create a home automation environment that gains capability and functionality over time as additional devices are purchased and connected. Even Apple is moving to position itself with product offerings to support home automation,[133] including the HomeKit[134] application.[135] Devices that can obtain near real–time electricity demand and usage from the AMI meter to optimize the net usage for the home are all candidates for a home automation system.[136] Thus EMS interfaces could be an incentive for residential customers to join the CCA.

7.5 Conclusions: BTM projects

1) BTM projects promote local economic development and job creation. Further, many behind-the-meter projects would save customers money by reducing their overall energy costs. Thus helping to fund BTM projects may attract customers to the CPSF. In order to increase investment in BTM projects, CPSF will need to offer programs that are economically beneficial to the system owners while at the same time have a neutral to positive impact on the overall economics of CPSF's program.
2) BTM projects are typically owned by their owners who are responsible for the projects, including assuming liability and risks for the systems. Accordingly, the majority of the economic benefits of BTM systems will accrue to their owners. BTM projects which are win-wins in that they benefit both the system owners and the CPSF include Demand Response (DR) projects and purchasing excess generation from customer-owned systems.
3) In order to increase investment in BTM projects, CPSF will need to offer programs that are economically beneficial to the system owners while at the same time have a neutral to positive impact on the overall economics of CPSF's program.

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[132] Electronic House. *Insteon Makes Nice with the Nest Thermostat - The Nest Learning Thermostat can now connect to a ton of home devices,* March 14, 2014*:* http://www.electronichouse.com/article/insteon_makes_nice_with_the_nest_thermostat/C212

[133] PC Magazine, Report: *Apple Working on Smart Home Hardware*, June 27, 2014: http://www.pcmag.com/article2/0,2817,2460203,00.asp

[134] Mac World, *Apple's HomeKit hub may already be in your house,* Jun 19, 2014: http://www.macworld.com/article/2364315/apples-homekit-hub-may-already-be-in-your-house.html

[135] Apple Developer Page for HomeKit: https://developer.apple.com/homekit/

[136] ZigBee Smart Energy Certified Products: http://zigbee.org/Products/ByStandard/ZigBeeSmartEnergy.aspx

Table 44 Range of Possible Economic Impact from Behind the Meter Projects (EE, DR, DER)

8.3	55
16.6	109
24.9	164
33.1	219

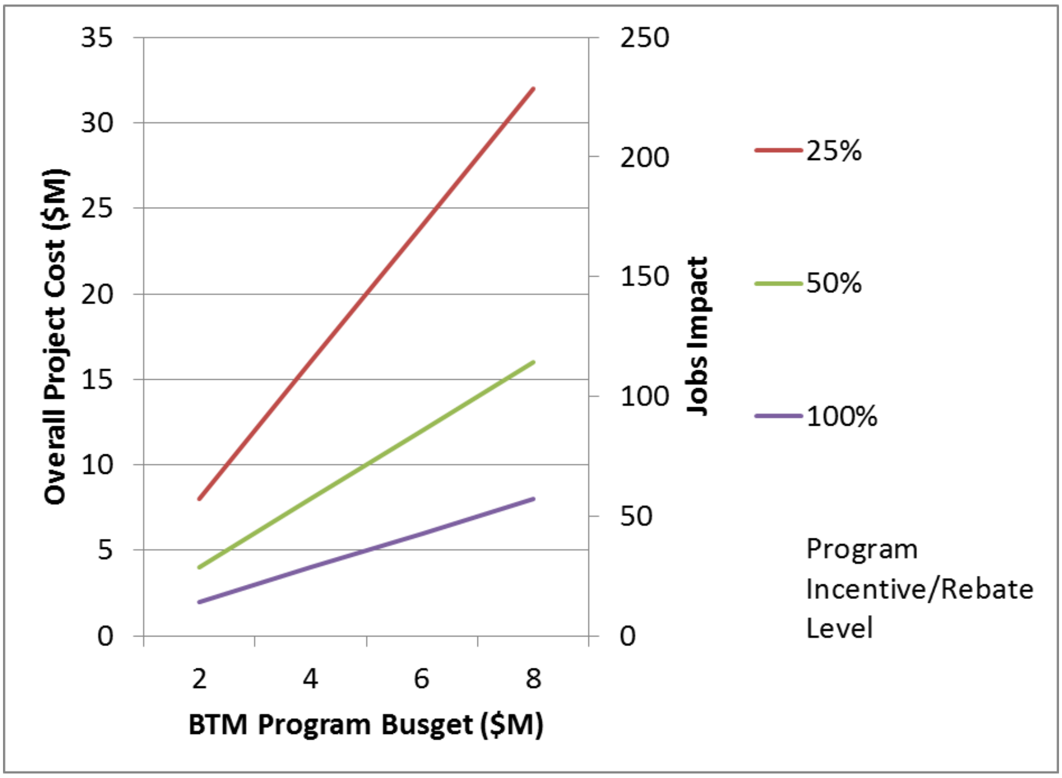

Figure 10 Range of Economic Impact based on BTM Program Incentive Levels

[137] According to Lori Mitchell, San Francisco Water, Power and Sewer Manager Renewable Energy Generation, SoSolar SF has paid $21 Million in incentives since the program start and the private investment based on submitted total project costs is $87 Million. This is equivalent to 24.1% of project costs being provided by program funding and provides the basis for the high level Behind the Meter economic impact assessment. Whether this is a realistic assumption completely depends on subsequent program design.

8 TASK 8: GO SOLAR SF INCENTIVES AND PROJECTS

Coordination of CPSF projects with the GoSolarSF program would leverage funding and would increase benefits for CPSF customers. CPSF marketing materials can and should list all programs available to CPSF customers, including GoSolarSF.

CPSF customers participating in EE programs should be informed of GoSolarSF opportunities and vice versa. CPSF programs should highlight the benefits of implementing Energy Efficiency (EE) projects first before implementing solar. Adding solar to an inefficient home or business will not derive maximum benefits. The GoSolarSF program currently requires incentive recipients to have proof of an energy audit in order to receive payment.

Participating contractors in the EE programs can refer customers to the GoSolarSF program. Customers already participating in EE programs may also be interested in participating in the GoSolarSF program. Similarly, customers in the GoSolarSF program may be more likely to be interested in CPSP EE programs. Thus offering an incentive to GoSolarSF and EE program contractors who cross-refer customers should be considered. Further offering a rebate to GoSolarSF recipients who participate in CPSF's EE programs should be considered.

Because PE is facing budget challenges which require the use of limited reserve funds, CPSF funding sources could provide timely financial benefits to the PE department. The PE department is currently funding the GoSolarSF program which is providing benefits to San Francisco and is reducing the use of carbon-based fuels. However, funding of GoSolarSF is presenting budget issues for PE. CPSF could eventually fund a portion, if not all of the GoSolar program, by integrating GoSolarSF into the overall CPSF local resource build-out plan and supporting all/part of the cost of the program through a portion of revenue from CPSF sales.

Currently GoSolarSF funds are distributed both directly to residents and businesses as well as to participating GoSolarSF contractors. We believe that the current dual funding approach helps to lower costs by allowing businesses and residents to select from any solar installer thus promoting a more competitive bidding process. Over time the amount of funding given to solar installers could be further decreased which would allow GoSolarSF to fund more projects for the same cost.

Incentive Structure for Fiscal Year 2014-2015 (All kW sizes are CEC-AC)										
Residential	**1 kW - 1.24 kW**	**1.25 kW - 1.49 kW**	**1.5 kW - 1.74 kW**	**1.75 kW - 1.99 kW**	**2 kW - 2.24 kW**	**2.25 kW - 2.49 kW**	**2.5 kW - 2.74 kW**	**2.75 kW - 2.99 kW**	**3 kW - 3.49 kW**	**3.5 kW & larger**
Select One: **Basic** or **Environmental Justice**	$500 or $600	$650 or $750	$1,000 or $1,100	$1,100 or $1,300	$1,300 or $1,500	$1,600 or $1,900	$1,700 or $2,100	$1,900 or $2,300	$2,000 or $2,500	$2,000 or $2,800
Add on if eligible: **City Installer**	$250	$300	$350	$400	$450	$500	$550	$600	$650	$700
Add on if eligible: **Low-income**	$2,000	$2,500	$4,000	$4,500	$5,000	$6,000	$6,500	$7,000	$7,000	$7,000
Non-profit: **$1,000/kW.** Cap: $50,000 cap per service site.										
Non-profit residential: **$1,000/kW.** Cap: $50,000 per service site.										
Business: **$500/kW.** Cap: $10,000 per meter and $50,000 per service site.										
Multi-unit residential virtual net metering: **$500/kW.** Cap: $500 multiplied by the number of assessed units at the building plus $10,000. Under no circumstances will a service site receive more than $50,000.										

Figure 11: 2014-2015 GoSolar Funding per Project[138]

8.1 Siting Criteria

SFPUC has solar monitoring stations that measured the amount of insolation throughout the City's eleven districts over a six year period. Solar insolation is the amount of solar radiation received on a given area over a given time period. Measured solar insulation for the City as measured by the SFPUC' solar monitoring stations are shown below in Figure 12. Note that the district boundaries were modified in 2012; however the average solar insolation values were not significantly impacted.

The SFPUC's data showed that there is a daily insolation of 4.1 or 4.2 kWh/m2/day for the west side of the city, and 4.5 or 4.6 kWh/m2/day for the east side of San Francisco. Thus, there is a 12% difference between the highest and lowest districts resulting in a slight advantage for sites in the eastern part of the City[139].

[138] SFPUC website, GOSolarSF Incentive, http://sfwater.org/index.aspx?page=133, retrieved August 25, 2014

[139] San Francisco Solar Power Map, http://www.sfog.us/solar/sfsolar.htm, online data as of 1/1/08, running average over six years, retrieved August 25, 2014

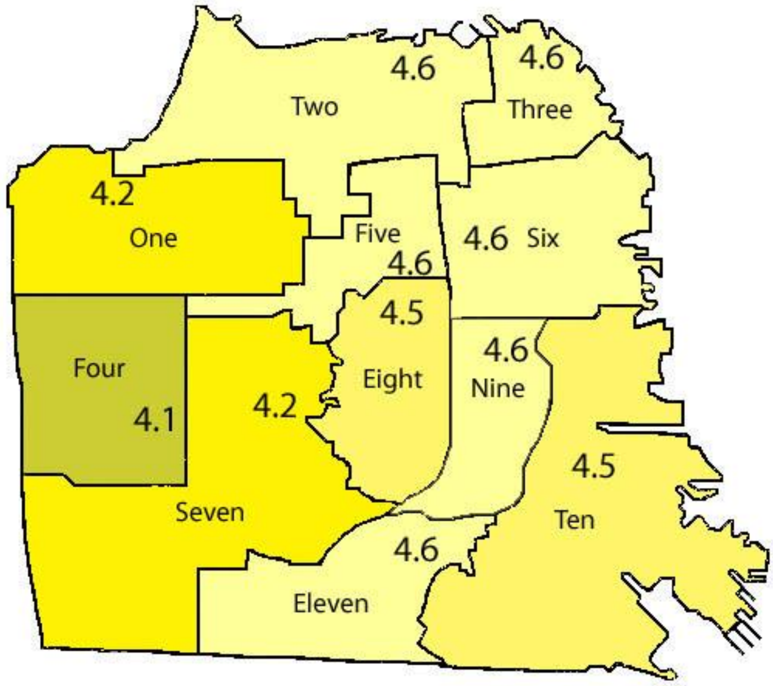

Figure 12: 2008 San Francisco Solar Power Map (note that district lines have changed)[140]

8.2 Potential through Low Income Properties

A portion of the GoSolarSF funding allocation is to low income properties[141], and using a similar approach a portion of EE fund programs can be targeted to low income residents. The draft roadmap strategy #3 calls for[142]:

1. Leveraging EE funds with existing programs that perform home improvements on low income properties
2. Prioritizing projects on the basis of cost-effectiveness
3. Identify low income properties to leverage the initial allocation
4. Determine if the CPSF will have EE funds from other sources
5. Apply to the CPUC for EE funds

Additionally, Assembly Bill 217 (Bradford, 2013) extended the Single-family Affordable Solar Homes (SASH) and Multifamily Affordable Solar Housing (MASH) programs of the California Solar Initiative with $108 million in new funding, and set several new goals for the programs[143].

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[140] San Francisco Solar Power Map, http://www.sfog.us/solar/sfsolar.htm, online data as of 1/1/08, running average over six years, retrieved August 25, 2014

[141] CleanPowerSF Draft Build-Out Roadmap and Strategies Draft, SFPUC Power Enterprise, June 2013, page 14

[142] CleanPowerSF Draft Build-Out Roadmap and Strategies Draft, SFPUC Power Enterprise, June 2013, pages 36-37

8.3 Pre-construction Evaluation

Similar to Section 2.3.3 and the project life cycle approach outlined in Figure 7, approval and timing for CPSF implementation needs to occur in order to proceed with CPSF coordination and support of GoSolarSF projects. There are several guides available to assess solar programs and ensure proper planning for customer sited projects:

- United States Environmental Protection Agency: Solar Photovoltaic Specification, Checklist and Guide[144]
- National Renewable Energy Laboratory: Solar Ready Buildings Planning Guide[145]
- National Renewable Energy Laboratory: Power Purchase Agreement Checklist for State and Local Governments[146]

8.4 Conclusions: GoSolarSF Incentives and Projects

1) Coordination of CPSF projects with the GoSolarSF program would leverage funding and would increase benefits for CPSF customers. CPSF marketing materials can and should list all programs available to CPSF customers, including GoSolarSF.
2) CPSF could eventually fund a portion, if not all of the GoSolar program, by integrating GoSolarSF into the overall CPSF local resource build-out plan and supporting all/part of the cost of the program through a portion of revenue from CPSF sales.

9 TASK 9: NET ENERGY METERING TARIFFS

9.1 SFPUC NEM Tariff Plan

To attract and encourage existing solar customers to participate in CPSF, a favorable Net Energy Metering (NEM) tariff is recommended which would reimburse CCA customers at a slightly higher rate than PG&E for the renewable energy produced by the customer. Net metering tariffs

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[143] CPUC Staff Proposal for the Implementation of Assembly Bill 217 Extending the Low-Income Programs of the California Solar Initiative: Single–family Affordable Solar Homes (SASH) Multifamily Affordable Solar Housing (MASH), July 2, 2014: http://www.cpuc.ca.gov/NR/rdonlyres/7D0007BD-E6F3-46EE-872F-DB7F00A328E5/0/AB217EnergyDivisionStaffProposalSASHandMASHJuly22014.pdf

[144] United States Environmental Protection Agency: Solar Photovoltaic Specification, Checklist and Guide https://www1.eere.energy.gov/buildings/residential/pdfs/rerh_pv_guide.pdf

[145] National Renewable Energy Laboratory: Solar Ready Buildings Planning Guide Technical Report NREL/TP-7A2-46078, December 2009: http://www.nrel.gov/docs/fy10osti/46078.pdf

[146] National Renewable Energy Laboratory: Power Purchase Agreement Checklist for State and Local Governments: http://www.nrel.gov/docs/fy10osti/46668.pdf

are not difficult to develop or implement. Essentially, a customer's energy generation is credited against their usage and the user is billed only for their net usage. At the end of a year, customers either pay for the net energy they used or are given a credit if they produced more than they used.

PG&E under Assembly Bill (AB) 920, is required to pay Net Surplus Compensation to reimburse solar PV customers who produce more energy than they use[147]. PG&E reimburses customers at the wholesale rate determined by the CPUC that has been 3 to 4 cents per kWh. Marin Energy Authority (MEA) pays a 1 cent per kWh premium above PG&E, or approximately 5 cents per kWh.

In order to encourage San Francisco residents and businesses to install additional solar PV, a similar 1 cent per kWh premium on excess generation is recommended.

A second approach, if CPSF wishes to avoid subsidizing solar owners at the expense of non-solar owners, then CPSF can reimburse solar customers for excess generation at the wholesale rate as determined by the SFPUC. CPSF's reimbursement would then be developed using a similar methodology as PG&E's reimbursement for excess generation.

A third and novel approach is to determine the net solar output during a given hour of the day and pay customers according to the CAISO day-ahead energy market price. With this approach, the customers would be paid less than they would be paid by PG&E if the wholesale market prices are low, but the customer also stands to be paid a premium on days when wholesale market prices are expensive.

[147] CPUC Net Surplus Compensation (AB 920) webpage, http://www.cpuc.ca.gov/PUC/energy/DistGen/netsurplus.htm

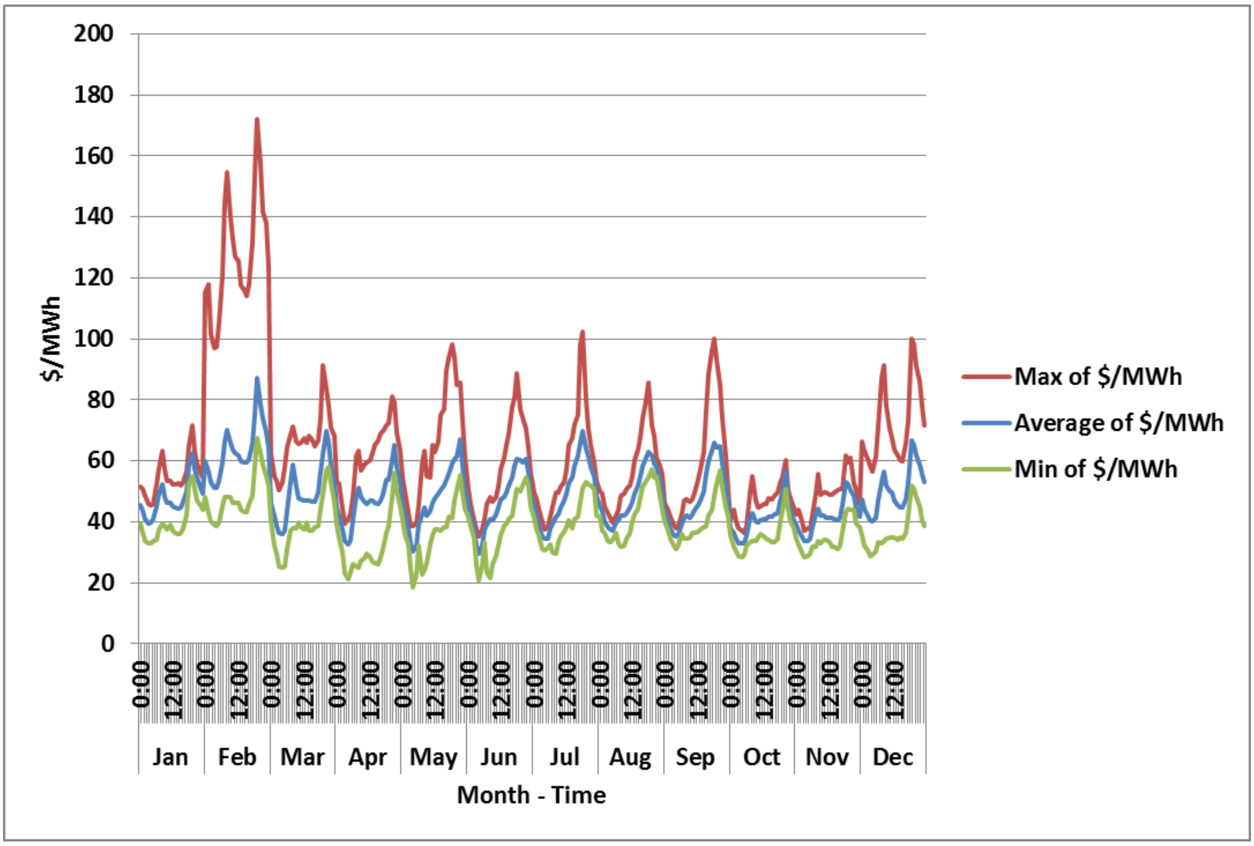

Figure 13 CAISO Day-Ahead Marginal Cost of Energy for PG&E (Oct 1 2013 – Sep 30, 2014)

The rate paid for solar generation should also be evaluated in terms of avoided costs to avoid concerns that solar customers are receiving benefits that are not also benefiting other CSPF customers.

9.2 Identifying NEM Participants

CCA implementation rules require that CPSF send at least 4 opt-out notices to each customer. As the CCA phases in customers, the opt-out notices will provide CPSF the opportunity to notify all solar customers of the premium payment for excess generation for qualified solar PV installations. We recommend the use of the required opt-out notices to notify customers of the premium rates for excess generation as well as the other programs that CPSF will be offering including the 100% renewable energy option and Light Green options.

To identify where customers have installed solar and enable direct contact with those customers to make them aware of NEM options under CPSF, San Francisco can review relevant permits filed by customers to develop solar facilities at their location. This same source of data should be utilized after CPSF implementation to understand which customers are installing solar and forecast how the increased distributed generation capacity will modify the net load for CPSF customers.

9.3 Conclusions: Net Energy Metering

A favorable Net Energy Metering (NEM) tariff is recommended as it would attract existing solar customers to the CPSF. Reimbursing CCA customers at a higher rate than PG&E pays for customer-generated renewable energy would both encourage solar owners to join the CPSF and would increase CPSF's use of local renewable generation. Implementing net metering tariffs would not be difficult.

10 TASK 10: FINANCING SUPPORT

Municipal electric utilities that own generation are typically capital-intensive enterprises and have an ongoing need to invest in new and existing generation assets. Utilities that own generation are large debt issuers and typically require consistent access to the capital markets to assure adequate sources of funding and to maintain financial flexibility. As such, a utility's financial strength is critical to its long-term viability and its ability to access financial markets. The financial performance and position of municipal electric utilities is evaluated by the financial markets to determine their ability to manage their specific business risks while assuring timely payment of debt service and compliance with certain financial legal covenants specified in the bond documents.

As specific renewable energy projects are identified and the costs associated with such projects are confirmed, it will be necessary for CPSF to prepare itself to approach the financial markets for necessary infrastructure financing. While the renewable energy program being considered by CPSF is expected to include a significant number of projects and related funding needs, a detailed capital program which would include specific projects, costs, and timing, has not yet been developed. As such, the discussions below present critical factors considered by the financial markets with respect to debt funding of municipal electric projects. Lacking a detailed capital program, this discussion is limited to providing a framework of planning and policy issues related to effectively positioning CPSF for access to capital markets, low-cost funding, and any private investment that may be considered.

10.1 Cost Recovery Framework

The strength and diversity of the service territory can indirectly influence a municipal electric utility's cost recovery framework. Larger more diverse service areas with greater economic wealth have a stronger cost recovery framework than smaller, less diverse service areas. In order to demonstrate the ability to support the necessary debt and address risks associated with the proposed projects costs recovery CPSF will need to consider the following:

- Near monopoly or competitive market,
    - While PG&E is considered a monopoly, certain qualifying Direct Access (DA) customers have a choice when selecting their ESP.
    - The introduction of the CPSF CCA provides a choice for all customers eligible within the CCA to select PG&E, CPSF or an alternative ESP (if the customer is DA eligible).

- Stability of the customer base, and
  - CCA customers can opt-out of CPSF service and elect to return to PG&E or their alternative ESP (if the customer is DA eligible).
- Characteristics of customer base and service area.
  - CPSF plans to utilize a 100% green and may offer a Light Green rate plan for generation highlights an understanding of the customer base in San Francisco which in general is more environmentally conscious than other locations in the state and country.

10.1.1 Monopoly or Competitive Market

In the U.S., municipal electric utilities have maintained a near monopoly role in their service area, limiting competitive threats to their customer base. This monopoly control, coupled with the unregulated rate setting process provides greater certainty of the utility's ability to access the economic resources of the region served.

The financial markets view the regulation of an electric utility's rates as a material weakness since it acts as a constraint on rate-setting. Municipal electric utilities have amortizing debt, so a regulatory lag that creates cost recovery uncertainty is a significant issue. Most state regulatory boards also have limited experience with public sector enterprises. Regardless of other considerations, including service area economic strength and customer concentration, should a municipal electric utility fall under state regulation (as normally applied to investor owned utilities) the assessment of the utilities overall ability to finance would be negatively influenced. However, in California, the CPUC regulates only investor-owned electric utilities. Therefore, in the case of CPSF, the financial risks associated with rate-setting regulations and rulemaking are mitigated.

However, CPSF will need to determine the process for customer rate review and approval in order to determine what level of review and oversight will be needed to approve proposed rate changes. It is our understanding that CPSF will be subject to the current processes of the Rate Fairness Board, SFPUC Commission and BOS. However, these processes are unclear and it is not known if they are sufficient for proper customer rate review. The risk of political resistance to rate increases could threaten the long term viability of CPSF if rates to not provide the revenue to cover the cost of power procurement and operations. This aspect is further discussed in Section 10.4.

10.1.2 Stability of Customer Base

Another important factor is the stability of the customer base that will be relied upon to support debt issued by the CPSF to fund renewable energy projects. Municipal electric utilities serving primarily a residential customer base (more than 50% residential sales) should benefit from more stable load and revenue trends given the typical usage pattern for this customer class. A customer base dominated by industrial load could prove prone to economic cycles and demand changes, which could affect revenue stability and the financial markets assessment of a utility's ability to generate a stable revenue stream sufficient to meet legal obligations under established bond covenants.

As the customer base of the CPSF is anticipated to be largely residential, fluctuations in revenues associated with the loss of volume sales should be mitigated resulting in a favorable assessment by the financial markets.

10.1.3 Characteristics of Customer Base and Service Area

When assessing the risks associated with a particular municipal electric utility, the financial markets take into consideration the service area's certain demographic metrics including population (historical and projected), employment trends, wealth indicators, and local economic diversity. Weak economic characteristics and limited economic diversity can be negative influencers. As an example, the limited economy of the Guam Power Authority's service area contributes to Moody's Investor Services issuing the utility a Ba1 rating, which is one of two below investment grade U.S. municipal electric utilities.

In particular, investors will evaluate the wealth indicators of the population that a utility serves to gauge the ability of customers to pay their electric bills, both currently and in the future, should rates rise. Affluent residential customers generally have a higher tolerance for higher overall rates, since the electric bill is a small part of their disposable income.

Based on the demographics and anticipated usage characteristics of the CPSF customer base, the risks associated with substantial fluctuations in revenues should be mitigated and, therefore, viewed favorably by the financial markets.

10.2 Commitment to Sound Financial Policies and Practices

A municipal electric utility's independent and local rate-setting authority guided, in part, by bond covenants, established financial policies and prudent governance is recognized as a fundamental strength by the financial markets. The financial markets perceive increased risk in the absence of the stability and certainty the utility business model provides by prioritizing a financial buffer to help mitigate the impact of modest stress events. For example, the political pressures impacting a municipal electric utility can result in an unwillingness or inability to establish sufficient rates to maintain sound financial metrics. Generally, the willingness to implement necessary rate increases will affect the relative financial performance of the utility. Without sound rate and financial policies that result in rate-setting that is predictable and timely, debt service coverage margins or financial liquidity may be compromised. As such, the willingness to fully recover system costs, including operating expenses, debt service, operating liquidity and critical system reinvestment, is often a leading indicator of the direction of future financial performance for a municipal electric utility. This highlights that some entities may have a high tolerance for exposure to risks readily anticipated through more conservative management practices and policies.

Another important consideration is the degree of support, or lack thereof, from a related governmental entity, since most municipal electric utilities are overseen by local governments. If the utility and the governmental entity are closely related and have a record of supporting interests in time of financial stress, this will be viewed positively by financial markets. This matters because a municipality may use its broader governance authority or financial resources to prevent financial deterioration of the electric utility, which serves to protect the interests of bond holders.

With this in mind, the CPSF should establish policies to ensure the electric utility maintains appropriate financial margins, including debt service coverage and operating reserve levels. Broad objectives for such policies might include:

- Generate sufficient revenues to fully recover system revenues requirements including infrastructure reinvestment, capital expenditures and targeted reserves.
- Plan effectively for rate and revenue stability.
- Maintain or enhance credit rating giving the CPSF access to low-cost funding.
- Adequately fund reinvestment in the system through a combination of unrestricted reserve funds and the prudent use of debt.

Specific rate and financial policies should address, at a minimum, the following elements:

- General Rate and Financial Policies
    - Establish a clear definition of system revenue requirements.
    - Establish policies and guidelines for General Fund Transfers, if any
    - Confirm rationale for establishing cost-based rate structures for the CPSF's customers.
    - Establish a process for periodic review of rates and charges to determine their appropriateness and effectiveness in meeting system goals and objectives.
    - Establish desired reserve funds (i.e. working capital fund; rate stabilization fund; emergency fund; renewal and replacement fund) and associated targeted minimum balances for each respective fund.
- Capital Planning and Debt Management
    - Multi-year capital improvement plan that endeavors to take into consideration customer growth, system capacity, potential regulatory impacts, and periodic replacement and renewal needs.
    - An approach to systematic process for the cyclical renewal and replacement of electric utility system's facilities and physical components to extend the useful life of critical assets and maintain operational integrity and high quality service levels.
    - Funding strategies and priorities that support the multi-year capital improvement plan.
    - The types, terms, and suitability of certain alternative debt instruments, as well as the total amount of variable-rate debt deemed appropriate.

- Management's rationale for the sizing of financial reserves and the adequacy of those reserves to cope with interest rate fluctuations and possible termination payments.
- Policies for ensuring a debt service coverage margin in excess of minimum requirements

10.3 Mitigation of Risks Associated with Cost of Purchased Power

Approximately 60% of California's electricity is produced by natural gas generators. A result, the price of natural gas has a significant impact on the price of electricity. While always an important consideration, the ability to automatically adjust rates for fuel or power purchase cost increases has become a more notable factor in the past decade given the fluctuations in natural gas prices, as well as ongoing hydrology risk, and the volatility of the wholesale power market. Utilities that have an automatic fuel and purchased power cost adjustment mechanism are able to recover these costs on a timely basis. Such adjustment mechanisms serve to narrow the potential drain on liquidity and the resulting impact on credit quality and are of particular importance should there be a fuel price spike or a forced outage of a generating unit.

To the extent the CPSF's power portfolio includes purchased power, rate mechanism(s) should be developed to mitigate the financial risks specifically associated with fluctuations in the costs of purchased power. The industry utilizes several alternatives to address this issue and it is recommended the CPSF evaluate these alternatives to determine which best meets the goals and objectives of the electric utility.

10.4 Political Concerns

Financial markets consider the governing body's transparency and timeliness in setting rates and charges necessary to ensure costs, including debt service, are fully recovered. A key measure is the number of days it takes to implement new rates and collect the additional revenues. A demonstrated record of willingness to charge the rates required to recover operating and capital costs, provide a cushion for debt service coverage (in the case of revenue bonds), and maintain a prudent level of liquidity.

Many industry professionals believe the rate-setting process will be tested in the next several years as power supply costs rise due to increased environmental regulation, demand growth remains slow due to the slow economic recovery, and utilities shift to cleaner and more expensive fuels.

A municipal governing body typically holds two readings with a final public hearing before new rates can be implemented and collected on the customer's bill. This process is typically concluded within 60 to 90 days. The longer and more complicated the process, the more pressure the delay may put on a municipal utility's liquidity. A mitigating factor for many utilities is the use of fuel hedging programs and enterprise risk management strategies, which, if effective, may be a positive factor in controlling costs while a new rate policy is being considered. In the end, the willingness to establish timely new rates to meet the appropriate cost recovery requirement is a heavy consideration to financial markets. This is of particular importance when considering a utility's capital program and whether future rates will be sufficient to manage increased debt service requirements.

Political risk that impedes a utility's willingness to enact rates and charges sufficiently and quickly to maintain the associated financial metrics for a utility will be viewed negatively by financial markets. In cases where a utility's management has established planning targets for financial metrics that are superior to the associated financial metrics for a utility's rating category and the utility has consistently met those targets, investors will likely me more prone to consider this utility.

With this in mind, CPSF should establish financial policies, such as those described herein, that serve to balance and even mitigate the potential impacts of political pressures.

10.4.1 Relationship with Local Government

A key consideration for financial markets is the relationship of the local government to the electric utility. This will not always be a factor, as some utilities have no fiscal relationship with a local government or the utility may have been established as a separate and independent authority. Consideration is given to who governs the utility, who sets its rates, and who issues the revenue bonds for the utility, as well as the degree to which the general government is responsible for supporting the utility in times of financial stress. Local governments generally have a strong record of supporting their municipal electric utilities in times of fiscal stress.

10.4.2 General Fund Transfers

General Fund Transfer policies are also an important issue considered by financial markets. The General Fund Transfer is the transfer of "surplus" utility revenues from the utility to a municipality's General Fund. Generally, an established General Fund Transfer policy that is accepted by both the utility and the local government adds strength for both entities as it increases the predictability of the transfer amount. However, when a transfer policy is established after a contentious debate and represents a substantial portion of the utility's own revenues, this could have a negative impact if it produces uncompetitive electric rates or leaves limited internal funds available for utility operations, maintenance, and repairs.

One of the policies that should be considered by CPSF would limit the exposure of the electric utility to the financial operations of the general government, so that system revenues can be relied on for use to operate and improve the utility. As related to transfers to the general fund, policies that specifically limit their scope and growth are viewed favorably by the financial markets. It is our understanding that City Charter prohibits general fund transfers from enterprise funds.

10.5 Management of Generation Assets

As an owner of power generating assets, CPSF's management of generation risks and power supply costs and reliability has an influence on other factors including the utility's financial metrics and competitiveness. The utility's ability to meet its current demand for electricity and plans for future demand has direct bearing on the utility's leverage, customer satisfaction on rates and service reliability, and often the political support for the utility.

As a capital intensive enterprise, a municipal electric utility's short-term decisions often have an impact on the utility's long-term success. Management's successful resource planning is fundamental to the utility's outlook given the need to provide low cost reliable power supply to its customers.

It is recommended CPSF develop an Integrated Resource Plan (IRP) to assist in meeting forecasted annual demands, including both peak and an established reserve. The IRP should evaluate the full range of alternatives, including new generating capacity, power purchases, energy conservation and efficiency, to provide adequate and reliable service at the lowest system cost. The process should also consider necessary features for system operation, such as diversity, reliability, dispatchability and other risk factors. By effectively integrating demand and supply resources, the IRP will facilitate the prioritization of capital additions (e.g. construction of new generation assets) and help to effectively match these assets to the necessary revenue generating load. This will allow CPSF to predict with some certainty the need for capital whether in the form of new debt or from available reserves. The lack of a comprehensive IRP will be viewed negatively by the financial markets.

10.5.1 Diversity

When evaluating the management of generation risks, financial markets consider the diversity of a utility's power supply and the cost and reliability of each source. Maintaining a diverse fuel and resource mix increases the utility's flexibility to manage peak demand while limiting the utility's exposure to volatile commodity and energy market prices, disruptions in the delivery of a single fuel source, or increased costs associated with a particular asset, like the cost of environmental compliance. To the extent possible, investors will review the utility's generation performance record, including availability; capacity factor; and heat rates. These performance measurements are generally evaluated in the context of the utility's overall power supply mix and the associated impact on the all-in cost of power supply, which drives the overall retail price charged to the end-use customer. Above market power supply costs could lead to higher retail charges to end-use customers, which would be a negative factor.

10.5.2 Reliability and Predictability

Financial markets consider the type of power generation used by the utility, since each type introduces its own set of challenges, which must be properly managed. Specific risks include the forecasted fuel price, transportation issues, and other factors unique to each fuel type; for example, Nuclear Regulatory Commission safety regulations for nuclear generation facilities, hydrology risks for hydroelectric generating units, and variability for solar and wind generation.

CPSF should be specifically aware of the diversity risk as policy is striving for up to a 100% renewable resource portfolio. Renewable resources (other than geothermal) are intermittent in nature. In the case of solar, the photovoltaic only generates when the sun shines. In the case of wind, the turbine only spins when there is a breeze. And in the case of hydroelectric, the water level determines when electricity generation is available as well as the need to delivery water to customers which is the top priority of the water system. .

10.6 Rate Competitiveness

Despite the closed retail market for almost all municipal electric utilities, an important advantage of the sector is its price competitiveness for the power it sells to its retail and/or wholesale customers. Financial markets would expect increased political risks if the utility has uncompetitive rates, leading to a potentially more challenging rate setting environment. High retail rates cause pressure on the governing body to lower rates, which could affect the utility's ability to recover costs and weaken its financial integrity. In addition, high rates also may discourage economic development and contribute to a stagnant or declining revenue base, which could impact investor security in the long-run. Municipal electric utilities that have large customers in industries where energy is a large portion of the company's operating budget and contribute significantly to a utility's net income, could face pressure from high industrial or commercial retail rates and decide to relocate elsewhere. This relocation could place additional upward pressure on electric rates for the remaining customers.

Generally, rate competitiveness is measured by a comparison of a utility's average system retail rate against the regional or state average rate, as well as the utility's competitiveness versus neighboring utilities. A comparison of retail rates is generally expressed in terms of the average revenue per kilowatt hour (cents/kwh). This unit measure has limitations since it doesn't distinguish between different load factor customers. Nevertheless, this measure is a useful benchmark that can allow comparisons within regional markets. Rate competitiveness is measured against state averages in the grid, but the assigned scores may be adjusted for a utility's competitiveness against other regional utilities or in specific customer classes.

CPSF should assess its ability to maintain competitive rates as a means to mitigate the risk associated with the potential migration of customers to back to PG&E (or alternative ESP for DA customers) where lower cost power may become available. The assessment should consider the potential impact of the long-term capital program and required funding. Should a regional rate comparison indicate that CPSF rates rank among the highest in the region, this could be viewed unfavorably by the financial markets.

10.7 Financial Metrics

Although financial ratio analysis is useful in comparing one utility's performance to that of another, no single financial ratio can adequately communicate the relative credit strength of these diverse entities. The relative strength of a utility's financial ratios must be viewed in the context of its business risks. Nevertheless, several common financial metrics are frequently used by the financial markets to assess the relative strength and credit worthiness of municipal utilities. These metrics generally focus on the following:

- **Cash Flow** – the ability of the utility to generate sufficient revenues to provide a margin (debt service coverage ratio, allowing it to effectively meet its legal obligations to bond holders.

- **Liquidity** - the ability of the utility to access liquidity (i.e. cash-on-hand; short term borrowings; commercial paper) provided financial flexibility and is looked on favorably by the financial markets.
- **Capital Structure** – the level of assets financed through debt should be monitored and carefully managed as an increasing debt to asset ratio could be looked on unfavorably by the financial markets.

The table below provides a listing of some of the financial metrics used by credit rating agencies to evaluate a municipal electric utility's financial performance. It is recommended that CPSF take such metrics into consideration in establishing financial policies and practices.

Table 45 Key Financial Metrics

Operating Revenues - Operating Expenses + Depreciation + Interest Income [a]	Provides a measure of cash flow from operations.
FADS/Total Annual Debt Service	Indicates the margin available to meet current debt service requirements.
(FADS + Fixed Charge − General Fund Transfer and/or PILOT)/ (Total Annual Debt Service + Fixed Charge) [b]	Indicates the margin available to meet all debt service and other fixed obligations.
Total Debt/FADS	Indicates the size of debt compared to the margin available for debt service.
Unrestricted Cash and Cash Equivalents / (Operating Expenses−Depreciation) x 365	Indicates financial flexibility, specifically cash and cash equivalents, relative to expenses.
(Unrestricted Cash and Cash Equivalents + Available Lines of Credit and Commercial Paper Capacity)/(Operating Expenses−Depreciation) x 365	Indicates financial flexibility, including all available sources of cash and liquidity, relative to expenses.

Total Equity/Capitalization	Provides a measure of cost recovery, leverage, and additional debt capacity.
Total Annual Debt Service/(Operating Expenses + Total Annual Debt Service – Depreciation)	Provides an indication of debt burden relative to cash operating expenses.
Total Debt/Total Customers	Provides a measure for relative comparison of leverage.
Variable-Rate Debt/Total Debt	Provides context for an issuer's short-term obligations.

Operating Margin/Operating Revenues	Provides a measure of operating stability and capacity to manage an increase in debt service.
Capex/(Depreciation + Amortization)	Indicates whether annual capital spending keeps pace with depreciation.
(FADS – Total Annual Debt Service – General Fund Transfer and/or PILOT)/Capex	Indicates a utility's ability to internally fund capex.
(Total Debt – Cash and Reserve Funds)/Net Utility Plant	Provides a measure of leverage relative to the book value of physical assets.
(General Fund Transfer + PILOT)/Operating Revenues	Indicates the degree to which a utility provides city or county general fund support.

Operating revenues exclude deferrals to and transfers from a rate stabilization fund.

Fixed charge – 30% of purchased power expense, which is an approximation of the associated fixed expense. FADS – Funds available for debt service. PILOT – Payment in lieu of taxes.

Source: Fitch Ratings U.S. Public Power Rating Criteria

10.8 Issuing Bonds/ Renewable Project Financing

Another consideration for financing is the continuing decrease in the costs for developing renewable generation, particularly solar photovoltaic (PV) systems. The National Renewable

Energy Laboratory (NREL) and Lawrence Berkeley National Laboratory (LBNL) estimate[148] that the cost of distributed solar PV systems will continue dropping and are estimated from $2 to $4.75 a watt by 2014. See Figure 14 below.

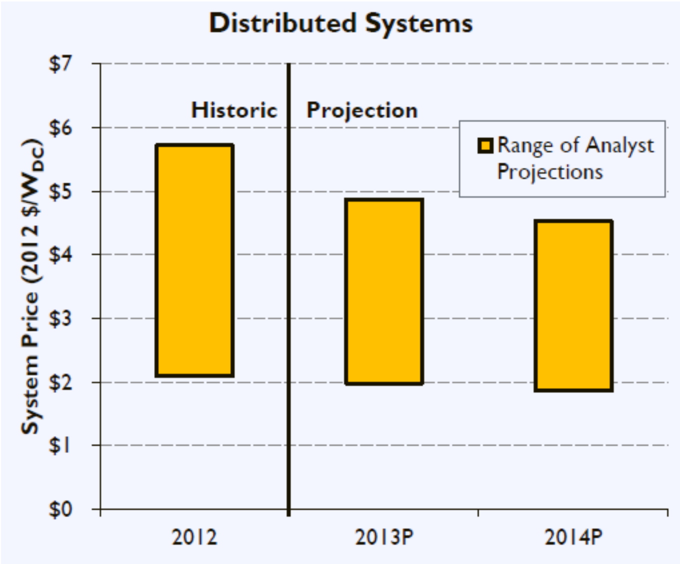

Figure 14 NREL/LBNL Cost Estimates for Solar PV

Distributed systems could be installed in San Francisco on rooftops, thus meeting the CPSF goal of in-city solar.

In earlier CCA plans, reasons cited for use of H Bonds to fund renewables are[149]:

- Allows for local ownership and control of energy resources
- Reduces the lifecycle cost of capital intensive green energy projects
- Raises money for building new green energy facilities
- Avoids the need for tax revenues
- Enables rapid deployment of renewables

As stated in the report "Black and Veatch's Renewable Energy Assessment Final Report[150] concluded that Power Purchase Agreements (PPAs) with transfer of ownership at year 7 would

[148] Photovoltaic System Pricing Trends: Historical, Recent and Near-Term Projections, 2013 Edition, July 16, 2013, page 27

[149] LPI CCA Program Report, December 31, 2008, page 5

[150] San Francisco Public Utilities Commission, Renewable Energy Assessment Final Report, 10 January 2014

have the lowest Levelized Cost of Electricity (LCOE) for any of the renewable projects analyzed."

Thus we believe the best financial instrument to purchase renewable energy is a PPA with transfer of the renewable generation facilities ownership to the CCA after many years. A PPA financial funding mechanism places the development of the renewable energy in the hands of commercial firms that are experts which would lower risks for CPSF and provide set payment amounts for the CPSF.

An important exception to the use of PPAs is for small hydro projects to continue to be proposed, managed and operated by the SFPUC who are the experts in San Francisco-area hydro projects. Thus the H bonds would not be needed until the renewable assets were transferred to the CCA 7 years down the road.

With lower renewable costs, particularly for solar PV systems, and the additional economic advantages of PPAs, a plan for the use of H Bonds does not appear necessary, at least not initially. The solar Investment Tax Credit (ITC) is scheduled to expire at the end of 2016. The need for H bonds should be re-evaluated when the ITC expires.

Please see Section 8 for information on the use of PPA's for renewable generation.

For CPSF renewable energy projects, a balance needs to be struck between the use of large centralized renewable projects and the use of distributed behind the meter projects located in the City. CPSF goals include the desire to site renewable energy in the City, to increase local jobs and to have renewable energy projects owned locally as well. In order to be competitive, CPSF's rate for its Light Green option that would provide less than 100% renewable energy, but a higher renewable percentage than PG&E, should be equal or ideally slightly less than PG&E's base rate. PG&E is currently providing 23.8% of their electricity sales with renewable power[151]. Rates for the 100% renewable energy will likely be set higher to account for the current higher cost of renewable energy.

The tariffs CFSP sets will include funds for both the cost of energy and a percentage for administrative costs as well as potentially funds for additional programs including EE and BTM programs. One method of setting tariffs would be to set the tariff equal to the cost of the 100% renewable generation plus the administrative costs and additional funds to support renewable energy build-out projects, BTM projects and EE programs. Similarly, the Light Green tariff would be set to similarly with the tariff equal to the cost of the renewable/non-renewable generation plus the administrative costs and additional funds to support BTM and EE programs.

[151] 2013 percentage as reported by the CPUC, http://www.cpuc.ca.gov/PUC/energy/Renewables/

10.9 Direct Support of Individual Project Development

As mentioned above, Black and Veatch's Renewable Energy Assessment Final Report[152] concluded that Power Purchase Agreements (PPAs) with transfer of ownership at year 7 would have the lowest Levelized Cost of Electricity (LCOE) for any of the renewable projects analyzed. We recommend acquiring renewable energy at the lowest LCOE available to CPSF. For CPSF, PPAs with fixed transfer dates offer several advantages that include low or no upfront development costs, limited risk as the developer is responsible for performance through year 7, and fixed predictable costs for renewable energy during the CCA's initial years.

A caveat is that the current 30% solar Investment Tax Credit (ITC) requires systems to begin operation prior to the end of 2016. Starting in 2017, the credit will drop to 10%. As noted above, solar PV costs are continuing to drop. Thus the decrease in the ITC percentage is expected to slow but not stop investments in solar PV systems.

However, it will be prudent for the CPSF to calculate costs assuming that the CCA may or may not be able to secure signed PPAs for generation to begin prior to 2016. More information on PPAs is contained in the next section.

As noted above, small hydro projects should continue to be proposed, managed and operated by the SFPUC who are the experts in San Francisco-area hydro and hydroelectric projects.

10.10 Conclusions: Financing Support

If CPSF moves forward with CCA service and the renewable program outlined herein, specific focus should be given to the financial considerations presented in this chapter. These considerations present factors that will be reviewed by the financial markets and will play a critical role in CPSF ability to issue future debt and the cost of this debt. The early establishment of financial related of policies and practices will be key in the success of the renewable program. Below is a restatement of the considerations presented in this chapter.

1) A CCA's financial strength is critical to its long-term viability and its ability to access financial markets. Financial markets will play a critical role in CPSF ability to issue future debt and the cost it pays for this debt. The early establishment of sound financial policies and practices will be key in the success of the renewable program.
2) The stability of CPSF's customer base will impact the financial market's assessment of the systems revenue stability. However, as the customer base of the CPSF is anticipated to be largely residential, the risk of substantial fluctuations in revenues associated with the loss of volume sales should be minimal resulting in a favorable assessment by the financial markets.
3) Demographic and usage characteristic are also an important factor in assessing revenue stability. Based on the demographics and anticipated usage characteristics of the CPSF

[152] San Francisco Public Utilities Commission, Renewable Energy Assessment Final Report, 10 January 2014, page 1-10

customer base, the risks associated with substantial fluctuations in revenues should be minimal and, therefore, viewed favorably by the financial markets.

4) CPSF should establish policies to ensure the electric utility maintains appropriate financial margins, including debt service coverage and operating reserve levels. Broad and specific financial policy objectives are outlined in Section 10.1 and key financial metrics are provided in Table 45.
5) To the extent the CPSF's power portfolio includes purchased power, rate mechanism(s) should be developed to mitigate the financial risks specifically associated with fluctuations in the costs of purchased power. The industry utilizes several alternatives to address this issue and it is recommended the CPSF evaluate these alternatives to determine which best meets the goals and objectives of the electric utility.
6) It is recommended CPSF develop an Integrated Resource Plan (IRP) to assist in meeting forecasted annual demands, including both peak and an established reserve. The IRP should evaluate the full range of alternatives, including new generating capacity, power purchases, energy conservation and efficiency, to provide adequate and reliable service at the lowest system cost.
7) CPSF should assess its ability to maintain competitive rates as a means to mitigate the risk associated with the potential migration of customers to service areas where lower cost power is available. The assessment should consider the potential impact of the long-term capital program and required funding.

11 TASK 11: FEED-IN TARIFFS AND POWER PURCHASE AGREEMENTS

11.1 Power Purchase Agreements

Competitive bidding processes are commonly used by public and municipal utilities, by CCA's such as MEA, SCP and Lancaster's Choice Energy and by ESPs for Direct Access customers as the primary vehicle in procuring longer-term, structured energy supplies from the market[153]. Market solicitations through Request for Proposal or Requests for Bid/Offer are the most common approach used by these market participants to purchase non-renewable as well as renewable energy for various contract durations and at the lowest available price. Responses to these

[153] For purposes of this section, we are associating Power Purchase Agreements (PPAs) with longer-term structured transactions with potentially customized terms and conditions as opposed to shorter-term (e.g. Day Ahead, Week Ahead, Month Ahead, etc.) market purchases that may be transacted under a Master Service Agreement (essentially an overarching PPA) where the terms and conditions are established and not renegotiated for each individual transaction.

solicitations may include production from a specific generation resource or may be offered as a "system" sale of the specified products and services. PPA's are also commonly associated with generation resource developers and are often used to define the financial revenues to be derived from the generation resource and the credit quality of the developer as well as the purchaser, PPA's are thus key components in the developer's efforts in securing project financing. As a purchaser, direct negotiation with a developer assures the purchaser of getting energy from a specific generation resource, at a negotiated price and usually for a longer period of time (usually 15-20 years).

11.1.1 Power Purchase Agreement Risks

As identified in the Navigant Risk Assessment Report[154], as well as EnerNex's own experience with industry best practices, key risks to be managed in the process of attracting, qualifying, evaluating, negotiating and selecting a supplier and developing a subsequent PPA[155] include:

- Identification and qualification of bidders
    - There are many potential sellers of energy products in the market place. Purchasers should establish ranking criteria that can be applied to screen and qualify potential suppliers. The procurement process can be long and detailed so purchasers should be cautious about investing time and effort in review of proposals from suppliers that may not be best aligned with the purchaser's needs (either from experience, size, market reputation, products offered, etc.). Typical screening criteria include experience in the specific energy market with the specific energy products desired, references from current similarly situated clients, financial strength and credit rating, appropriate licensing and credentials[156].
- Define and understand the CPSF supply portfolio strategy and the implications
    - Before making a solicitation, a purchaser should thoroughly understand the products and services they need and seek to secure. The specific products will reflect the supply portfolio strategy that has been developed and agreed to
- Identify and understand the products and services that are being sought from a bidder
    - Presenting prospective suppliers with as detailed and specific product requirements as possible in the solicitation will facilitate suppliers making the most competitive bids with the least amount of misunderstanding and/or key

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[154] Risk Assessment Report, San Francisco Community Choice Aggregation Program CleanPowerSF, Draft, July 29,2009, pp 3-5

[155] These risks are applicable and should be understood and considered for any structured market transaction and not limited to PPA's associated with development of a specific generation asset.

[156] Licenses and credentials include FERC power marketing license as well as appropriate registration with regional markets and ISO's.

deal points left open to interpretation. Leaving the specifics open for bidders to interpret will most likely result in disparate responses and potentially make it impossible to compare responses between bidders on a consistent basis.

- Identify and understand how these products and services will be contractually defined and ultimately settled and what the implications are for Supplier and CPSF in terms of data, systems and supporting processes
    - Energy products can be complicated and the detail associated with accounting for and ultimately paying for the products delivered can include huge amounts of underlying data[157] and associated handling and processing. Defining the data, the calculations and how information is created, reviewed exchanged, disputed and ultimately paid for should be a part of the RFP/Q evaluation and key component in selecting the winning bidder. The supporting systems should be well defined and any development costs associated with integrating information systems should be identified and incorporated into the contract.
- Identify and understand the various risks associated with the product(s) being procured, including but not limited to:
    - Price risk
    - Volume Risk
    - Term Risk
    - Supplier creditworthiness and default risk
    - Supplier and product diversification risks (correlated with CPSF supply portfolio strategy)
- Define and understand PPA termination risks including:
    - Unwinding of the supply portfolio PPAs in the event of CPSF program termination
    - Transitioning from one supplier to another (transition period, support requirements, etc.)
- Define and understand dispute resolution needs to be incorporated into PPAs:
    - Arbitration
    - Liquidated damages

[157] For example, actual energy consumed versus forecast will always be different. The basis upon which the excess energy is resold or incremental energy is purchased must be well defined. The underlying data needed to facilitate the settlement may come from several sources including the local ISO, the local distribution utility, the seller, the buyer and the end use customer.

11.1.2 Power Purchase Agreements – Open Season Process

A cornerstone of the CPSF program is the belief in and commitment to developing local renewable resources that will be incorporated into the CPSF supply portfolio and in-turn be used to meet the needs of CPSF's customer base. In the initial phases of the CPSF program, the supply portfolio will, out of necessity, be constructed from a combination of as-available energy and capacity from Hetch Hetchy and a mixture of short-term and longer-term wholesale power products procured from the market place. As discussed in Section 11.1.1, CPSF will likely follow a competitive solicitation process (through RFQ/RFP/RFO mechanisms) for procurement of various structured power products and subsequently develop PPAs[158] with the winning suppliers of those products.

CPSF has a vested interest in promoting and seeing local renewable resources developed and as such, must send the correct signals to the marketplace to signal interest and direct size, technology and timing for new resources sought. Based on the Navigant Risk Assessment Plan[159], the Marin Energy Authority, Sonoma Clean Power acquisition processes, and EnerNex's experience with industry best practices, an annual Open Season solicitation process is a proven and efficient method for CPSF to send appropriate signals to the marketplace and through solicitation responses, an effective way to gauge the market interest and capability to develop cost effective projects that may best meet CPSF's supply portfolio needs. Making the Open Season solicitation an annual process assures that the market is kept apprised of CPSF near and longer term needs. Moreover, this process provides CPSF with valuable information from the market regarding price, technology, development timing and other considerations that can be incorporated into CPSF's resource planning process.

An example of an Open Season solicitation is provided in Appendix B.

11.2 Feed-In Tariffs

Feed-in tariffs (FIT) offer key benefits to CPSF which include the ability to acquire local clean renewable energy at stable prices under multi-year contracts. Further local projects will offer opportunities for local jobs and the potential for money spent on energy to remain in the local economy. Another benefit is that long-term contracts typically used offer price stability for the CPSF as well as stable long-term return on investment for the renewable system owners.

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[158] Most participants in the wholesale structured products market utilize a form of the Edison Electric Institute (EEI) standard power sales contract. In many cases, this contract is used as the basis for a Master Service Agreement (MSA) which provides an overarching contract structure against which the parties can execute additional transactions. As a western system electric market participant, SFPUC PE is very familiar with these contract practices and could likely leverage existing counterparty arrangements when procuring supply products for the CPSF portfolio.

[159] Risk Assessment Report, San Francisco Community Choice Aggregation Program CleanPowerSF, Draft, July 29,2009, pp 3-4

To encourage local renewable generation resources, CPSF should offer feed in tariffs to obtain clean renewable energy locally at a rate and rate structure that works for CPSF as well as the developer. MEA accepts projects of 1 MW or less[160] while PG&E accepts project up to 3 MWs.[161] Typically higher prices are offered for solar generation which is produced during peak usage periods than for wind which is intermittent. Base load generation from devices such as fuel cells is typically acquired for a price between solar and wind generation.

Generation acquired under FIT for CPSF must meet PG&E interconnection[162] and metering requirements, as would any other distributed generation project. CPSF can offer FIT under standard rates per MWH delivered for the various types of generation e.g. peak, base and intermittent.

CPSF can establish a FIT program by:

1) Notify current and potential future renewable system owners of CPSF's intent to provide FIT via the CPSF website.
2) Develop a standard template for a Power Purchase Agreement between CPSF and the system owners. See an example PPA at http://sonomacleanpower.org/wp-content/uploads/2014/09/SCP-FIT-PPA-Approved-2014-07.pdf
3) Perform due diligence to ensure the viability of each system owner
4) Perform a worst case scenario analysis to determine CPSF's action in case a FIT participant were to default.

11.3 Conclusions: Power Purchase Agreements and Feed-in-Tariffs

1) Competitive bidding processes for Power Purchase Agreements (PPAs) are commonly used by CCA's including MEA, SCP and Lancaster's Choice Energy as the primary vehicle to procure longer-term, structured energy supplies from the market[163]. Market

[160] Marin Energy Authority Feed-In Tariff for Distributed Renewable Generation (FIT), http://marincleanenergy.org/PDF/MCE_FIT.pdf

[161] PG&E Renewable Feed-In Tariffs, http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/standardcontractsforpurchase/index.page

[162] Electric Rule 21 tariff for interconnection, operation and metering requirements of distributed generators: http://www.pge.com/en/b2b/energytransmissionstorage/egi/grid/rule21/whatisrule21/index.page

[163] For purposes of this section, we are associating Power Purchase Agreements (PPAs) with longer-term structured transactions with potentially customized terms and conditions as opposed to shorter-term (e.g. Day Ahead, Week Ahead, Month Ahead, etc.) market purchases that may be transacted under a Master Service Agreement (essentially

solicitations through Request for Proposal or Requests for Bid/Offer are the most common approach used by market participants to purchase non-renewable as well as renewable energy at the lowest available price. Responses to solicitations may include production from a specific generation resource or may be offered as a "system" sale of the specified products and services.

2) Feed-in tariffs (FIT) offer key benefits to CPSF which include the ability to acquire local clean renewable energy at stable prices under multi-year contracts. Further local projects will offer opportunities for local jobs and the potential for money spent on energy to remain in the local economy. Another benefit is that long-term contracts typically used offer price stability for the CPSF as well as stable long-term return on investment for the renewable system owners.

12 TASK 12: HYDROELECTRIC GENERATION

12.1 Use of Hetch Hetchy

Currently Hetch Hetchy power is used to first serve the City's municipal loads and the Modesto and Turlock Irrigation districts[164]. As previously stated in section 1.1.1, excess Hetch Hetchy power is currently sold to other municipalities through the other qualifying public power providers and public entities. Excess power is sold to municipalities at wholesale market rates.

In terms of costs, as noted in inputs from the SFPUC, *". . . it is unlikely that substantial program savings will accrue, unless power is provided to CPSF at a significant discount to market prices. Such a discount would represent a subsidy by municipal [165]customers for CPSF customers, which is contrary to current direction from Commission[166].*" Thus, although contracts with the Modesto and Turlock Irrigation Districts expire in 2015[167], it is not recommended that the CPSF attempt to purchase power currently used by the Modesto and Turlock Irrigation Districts. After serving the Irrigation Districts and the current City customers, it is recommended that CPSF purchase excess Hetch Hetchy power.

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an overarching PPA) where the terms and conditions are established and not renegotiated for each individual transaction.

[164] LPI CleanPowerSF Final Regulatory & Policy Report, page 90, March 2013

[165] Text of the Raker Act, Section 6, first sentence, Committee on Public Lands U.S. Senate, 63rd Congress, 1913

[166] SFPUC Review of Local Power Inc. Deliverable -- First Draft Regulatory and Policy Review Report, 2013, page 3

[167] LPI CleanPowerSF Final Regulatory & Policy Report, page 29, March 2013

12.2 High Priority Customer

Working with the SFPUC and Commission, it should be possible for CPSF to become a customer who receives priority after the current municipal customers including city buildings, SFO, SF hospital, police, fire, and MUNI vehicles and the retail customers at Hunters Point and Treasure Island.

Another potential approach would be for the CPSF to work with the Water Department to co-fund projects such as small hydro and Hetch Hetchy system performance improvements. By mutual agreement, the energy produced from these projects could be sold to CPSF. In order to do so, policy decisions would need to be made. Ultimately it is up to the Board of Supervisors to decide how and when energy produced by small hydro projects are used.

12.3 Small Hydro

Building on the content in Section 0 evaluating small hydro investments is expanded upon in this section based on a very high-level simplified screening of potential hydro opportunities[168]. As with the identified solar projects in Section 1), hydro project costs need to be verified and a more thorough project planning effort undertaken prior to proceeding with the projects or being able to draw more conclusive recommendations. Small hydro projects have potential, but more comprehensive work is needed to identify the best cost-effective hydro projects. No small hydro project can be implemented without a review to verify that the water system will not be negatively impacted.

Further, the CPSF portfolio composition would need to account for yearly variations in available Hetch Hetchy power. The base energy portfolio could be reduced or increased to accommodate the power fluctuations due to variances in the amount of available Hetch Hetchy power.

Some of the identified projects are already under development including the Sunol Small Hydro project scheduled for completion in 2015. Two new hydro projects, Calaveras/Sunol and University Mound, are already under development. If all 14 of the projects listed[168] were implemented, 7.1MWs and 141,397 MWhs of energy would be generated annually.

The Sunol small hydro project is being funded by the Water Department. The amount of energy that may be available for export over Hetchy lines for other loads - and at what price - would need to be ascertained by consulting with the Water Department. Any decision to use small hydro power for CPSF would need to be a Commission policy decision.

12.4 Hetch Hetchy Power Use Plan

As discussed in paragraph 12.1 above, CPSF can likely use Hetch Hetchy power as a clean power source. In order to utilize Hetch Hetchy power, the following steps are needed:

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[168] Draft SFPUC Water & Power System, Hydroelectric Renewable and Clean Energy Generation Opportunities table, Long-term Renewable Plan (High Level Screening Only)

1) Verify with the City Attorney's Office that use of Hetch Hetchy power by CPSF meets the legal requirements of the Raker act. In particular, enlist the City Attorney to verify that selling power to CPSF meets the requirements in section 9(l) excepted here:

    (l) That the said grantee shall, upon request, sell or supply to said irrigation districts, and also to the municipalities within either or both said irrigation districts, for the use of any land owner or owners therein for pumping subsurface water for drainage or irrigation, or for the actual municipal public purposes of said municipalities (which purposes shall not include sale to private persons or corporations) any excess of electrical energy which may be generated, and which may be so beneficially used by said irrigation districts or municipalities, when any such excess of electric energy may not be required for pumping the water supply for said grantee and for the actual municipal public purposes of the said grantee (which purposes shall not include sale to private persons or corporations) at such price as will actually reimburse the said grantee for developing and maintaining and transmitting the surplus electrical energy thus sold; and no power plant shall be interposed on the line of the conduit except by the said grantee, or the lessee, as hereinafter provided, and for the purposes and within the limitations in the conditions set forth therein:

    Provided, that said grantee shall satisfy the needs of the landowners in said irrigation districts for pumping subsurface water for drainage or irrigation, and the needs of the municipalities within such irrigation districts for actual municipal public purposes, after which it may dispose of any excess electrical energy for commercial purposes.

2) Work with the SFPUC to develop an estimate of the amount of power which will be available for sale to CPSF including 1) new generation currently being developed by the Water Department such as the Calaveras Small Hydro facility being developed at the Sunol Valley Water Filtration (SVWTP) plant; and 2) excess power currently being sold to qualifying public power providers and public entities.

3) Working with the Commission, determine the fair price for CPSF to pay for Hetch Hetchy power.

4) If the CPSF intends to follow LPI's plan to terminate the distribution of the energy to the irrigation districts, then at least three years before CPSF will use Hetch Hetchy power, request the City Attorney's office terminate the Modesto and Turlock Irrigation District power contracts while still retaining Water Agreements with the districts. Although not recommended, it would be necessary to verify with the City Attorney's Office that the contracts with Modesto and Turlock Irrigation districts

could be terminated. Contract termination requires a 2.5 year advance notice[169]. We do not recommend attempting to terminate the Modesto and Turlock Irrigation Districts power contracts.

5) Load the Hetch Hetch power available to CPSF into the annual power procurement portfolio.

12.5 Conclusions: Hydroelectric Generation

1) Working with the SFPUC and Commission, it should be possible for CPSF to become a customer that receives priority for Hetch Hetchy power after the current municipal customers including city buildings, SFO, SF hospital, police, fire, and MUNI vehicles and the retail customers at Hunters Point and Treasure Island.
2) Review of existing, albeit varying cost estimates, indicates that build out of small hydro projects by the City's Water Department as well as PPAs to acquire solar and wind energy from local and regional projects are the most cost effective sources of renewable energy.

[169] LPI CleanPowerSF Final Regulatory & Policy Report, page 29, March 2013

APPENDIX A – LIST OF RESOURCES

The following is a list of the major resources that EnerNex reviewed and used in developing this assessment. Materials were provided by LAFCo, SFPUC PE or obtained in the public domain.

- Background on CPSF, Change in Electric Supply Strategy, CPSF Strategy Study Scope; email from Kim Malcom (SFPUC CPSF) to Jason Fried SF LAFCo. April 29, 2014.
- "*San Francisco Public Utilities Commission Power Basics*"; provided by Kim Malcom at meeting with SFPUC PE staff on May 5, 2014.
- "*How to get from 11.5 cent rate to 9 cent rate*"; a three page document prepared by SFPUC PE Staff and provided by J.Fried via email on April 29, 2014 (file name CCACOSTS).
- CPSF – Procurement Options; a single page document prepared by SFPUC PE Staff and provided by J.Fried via email on April 29, 2014 (file name CPSF_ProcuremntOptions).
- "*CPSF Resource Procurement Strategies*"; a memo prepared by K.Malcom to AGM B.Hale dated June 20, 2013, provided by J.Fried via email on April 29, 2014 (file name InhouseenergymgtMEMO).
- "*Comparison of Customer Energy Program Models (December 2013)",* a 3 page document prepared by SFPUC PE Staff and provided by J.Fried via email on April 29, 2014 (file name POUand CCAOptions_SD_v2).
- Description of SFPUC roles and responsibilities; an email from AGM B.Hale to J.Fried dated May 2, 2014.
- "*Responses to Questions from March 3, 2014 Joint Meeting of the San Francisco PUC and LAFCo*."; a memo from AGM B.Hale to SFPUC Commissioners, GM H.Kelly and ED N.Miller, dated April 25, 2014. Included Energy Trading Risk Management Policy. Received from J.Fried via email on April 25, 2014.
- "*Proposed Not-to-Exceed Rates*", a slide deck prepared by SFPUC Finance dated July 26, 2013 provided by J.Fried via email on May 2, 2014.
- "*FY1314 CCA Classifications by Salaries*"; an Excel spreadsheet provided by J.Fried via email on May 2, 2014
- "*Response to Supervisor John Avalos Inquiry (Reference #20130903-002)*"; a memo from GM H. Kelly to SFPUC Commissioners, dated October 1, 2013. Obtained from SFPUC web site.
- "*San Francisco's 2011 Updated Electricity Resource Plan*", March 2011. Obtained from SFPUC web site.

- "*Memorandum of Understanding Between SFPUC and LAFCo Regarding CCA Program*", a MOU dated April 17, 2009. Obtained from SF BoS web site as an attachment to BoS meeting agenda for March 25, 2013.
- "*The Raker Act*", full text; obtained from MID web site.
- "*ETRM Software Implementation and ACES Power Scheduling Replacement Proposal";* slide deck dated November 8, 2013; obtained from SFPUC web site.
- "*Draft Term Sheet – Noble Americas and CCSF*"; undated; obtained from SF LAFCo website.
- "*Energy Purchase and Sale Agreement*"; non-binding draft. An MSA between Shell Energy North America and CCSF"; undated. Obtained from SF LAFCo. Website.
- "*SFPUC Comprehensive Annual Forecast Report, FY 2012-13*"; obtained from SFPUC web site.
- "*FY 2014-15 and FY 2015-16 Proposed Budget, Workshop and Discussion*"; slide deck used at SFPUC meeting January 14, 2014. Obtained from SFPUC web site.
- "*Hetchy Power- 2. Budget Summary*"; FY 2014-15 and FY 2015-16 budget request. Associated with January 14, 2014 budget review with SFPUC. Obtained from SFPUC web site.
- "*Hetchy Power- 3. Operating Budget*"; FY 2014-15 and FY 2015-16 budget request. Associated with January 14, 2014 budget review with SFPUC. Obtained from SFPUC web site.
- "*Hetchy Power- 5. Ten-Year Financial Plan/Rates*"; FY 2014-15 and FY 2015-16 budget request. Associated with January 14, 2014 budget review with SFPUC. Obtained from SFPUC web site.
- "*Proposed Not-to-Exceed Rates*"; SFPUC Finance; a slide deck presented at SFPUC meeting on August 13, 2013.
- "*CPSF Update*"; a slide deck presented to a joint meeting of the SFPUC and LAFCo on July 9, 2013. Obtained from SFPUC web site.
- "*CPSF Update*"; a slide deck presented to a joint meeting of the SFPUC and LAFCo on March 25, 2013. Obtained from SFPUC web site.
- "*Hetch Hetchy Power System – Generating clean energy for San Francisco*"; July 2013. http://www.sfwater.org/modules/showdocument.aspx?documentid=4202

APPENDIX B – LIST OF ACRONYMS

Assembly Bill

Automated Dispatch System

Ancillary Services

Automated Demand Response

Building Automation and Control System

Bay Area Regional Energy Network

Board of Supervisors

Behind-the-meter

Commercial and Industrial

California Independent System Operator

Community Choice Aggregation or Community Choice Aggregator

Community Choice Aggregation Service Request

California Energy Commission

Customer Information System

Critical Peak Pricing

Clean Power San Francisco

California Public Utilities Commission

Day Ahead

Direct Access

Demand Analysis Working Group

Direct Current

Department of Energy

Demand Response

Demand Response Provider

Demand Side Management

Energy Communications Network

Energy Efficiency

Energy Efficiency and Conservation Block Grant Program

Energy Management System

Energy Savings Assistance

Electricity Service Provider

Energy Trading and Risk Management

Energy Trading Risk Management Policy

Feed-In Tariff

Full-Time Equivalent

Greenhouse Gas

Home and Business Area Networking

Hour Ahead Scheduling Process

Hispanic Chambers of Commerce of San Francisco

Hetch Hetchy Power System

Heating, Ventilation and Air Conditioning

Interconnection Agreement

Initial Capital Cost

Investor Owned Utility

Integrated Resource Plan

Investment Tax Credit

Jobs and Economic Development Impact Model

Kilowatt-Hour

Local Agency Formation Commission

Lawrence Berkeley National Laboratory

Levelized Cost of Energy

Locational Marginal Price

Local Power Incorporated

Local Resource Adequacy Requirement

Load-Serving Entity

Multifamily Affordable Solar Housing

Marin Clean Energy

Meter Data Management Agent

Marin Energy Authority

Multi-Family Energy Efficiency Program

Modesto Irrigation District

Memorandum of Understanding

Megawatt

Megawatt-Hour

Net Energy Metering

National Renewable Energy Laboratory

On-Bill Financing

On-Bill Repayment

Operation Meter Analysis and Reporting

Portfolio Content Category

Peak Day Pricing

Power Enterprise

Pacific Gas & Electric Company

Payment In-Lieu of Tax

Pricing Nodes

Program Opportunity Notice

Power Purchase Agreement

Public Private Partnership

Photovoltaic

Resource Adequacy

Resource Adequacy Requirement

Renewable Energy Certificate or Renewable Energy Credit

Request for Information

Request for Offers

Request for Proposals

Return on Investment

Renewable Portfolio Standard

Real Time

Single-Family Affordable Solar Homes

Senate Bill

Schedule Coordinator

Scheduling Coordinator Application

Scheduling Coordinator Identification

San Francisco African American Chamber of Commerce

San Francisco Public Utilities Commission

Settlement Quality Meter Data

Settlement Quality Meter Data System

Sunol Valley Water Treatment Plant

The Energy Authority

Turlock Irrigation District

Western Electricity Coordinating Council

Western Renewable Energy Generation Information System

Zero Net Energy

APPENDIX C – MEA 2014 OPEN SEASON INSTRUCTIONS FOR RENEWABLE ENERGY OFFERS

Marin Clean Energy 2014 Open Season Instructions

1) Introduction: Marin Clean Energy ("MCE") has made a commitment to procuring increasing amounts of renewable and carbon-free energy for its customers. In fact, MCE customers currently receive our Light Green retail electricity product, which includes a minimum 50 percent renewable energy ("RE") content as well as additional carbon-free supplies – in aggregate, MCE's supply portfolio was over 60 percent carbon-free in 2013. MCE also offers a voluntary 100 percent renewable energy Deep Green product, which is Green-e Energy certified. As part of its ongoing effort to deliver environmentally responsible, competitively priced retail service options, MCE has established an annual Open Season procurement process ("Open Season"). The Open Season provides a competitive, objectively administered opportunity for qualified suppliers of various energy products to serve MCE customers. The specific energy products requested through the Open Season process may vary from year to year, depending on MCE's ongoing procurement efforts and projected resource needs.

Instructions for participating in the 2014 Open Season process are described below.

By participating in this Open Season process, a respondent acknowledges that it has read, understood, and agrees to the terms and conditions set forth in these instructions. MCE reserves the right to reject any offer that does not comply with these requirements. Furthermore, MCE may, in its sole discretion and without notice, modify, suspend, or terminate this Open Season process and MCE will not be liable, by reason of any of the above actions, to any respondent. This Open Season process does not constitute an offer to buy or create an obligation for MCE to enter into an agreement with any party, and MCE shall not be bound by the terms of any offer until MCE and respondent have entered into a binding executed agreement, enforceable in accordance with its terms.

2) Standardized Response Template: All respondents must use the current Standardized Response Templates ("Templates") provided by MCE. MCE will post the Templates on its website (http://marinCleanEnergy.org/energy-procurement) and will require respondents to independently access and download the Templates prior to response preparation. An unmodified version of the appropriate Template must be completed in its entirety based on instructions provided in the Template. MCE may update the Templates from time to time, so respondents are encouraged to periodically visit

MCE's website to determine if any changes have been incorporated in the Templates. Only submittals of the currently applicable Templates will be reviewed.

3) Renewable Energy Need: Based on recent updates to the MCE load forecast, the following open positions have been identified through the 2020 calendar year:

Open Position, RPS-Eligible Renewables (MWh)	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
	-	-	-	-	45,000	55,000	65,000
Portfolio Content Category 2							
Subtotal - Open Position, RPS-	**55,000**	**35,000**	**35,000**	**50,000**	**95,000**	**110,000**	**120,000**

Currently, MCE is not seeking annual delivery volumes in excess of the volumes presented in this table. Therefore, MCE will not be considering bids for Bucket 1 products with delivery start dates that will occur prior to January 1, 2018. Note: MCE periodically updates this forecast in consideration of ongoing procurement efforts, resource planning initiatives and/or related policies adopted by MCE's governing board. Such updates may not be reflected in posted Open Season materials but may impact MCE's planning and procurement decisions as well as the evaluation of offers submitted in response to this Open Season process.

4) Requested Renewable Energy Products:

A. Portfolio Content Category 1 ("Bucket 1") Eligible Renewable Energy meeting the following criteria:

i. **Resource Location:** The point of physical interconnection for any eligible generator must be within the area generally termed NP15, as defined by the CAISO. Evaluative preference will be given to any resource located within 100 miles of San Rafael, California.

ii. **Product:** Electric energy, Green Attributes/Renewable Energy Credits and Capacity Attributes (if available).

iii. **Resource Eligibility:** All proposed generating resources must be certified by the California Energy Commission ("CEC" or "Commission") as Eligible Renewable Energy Resources (or must receive CEC certification prior to the commencement of any energy deliveries proposed in the appropriate response Template), as set forth in applicable sections of the California Public Utilities Code ("Code"), which may be amended or supplemented from time to time. Each respondent shall be responsible for certification of the proposed resource through the certification process administered by the CEC and shall be responsible for maintaining such certification throughout the contract term.

iv. **Generating Capacity:** Minimum one (1) megawatt ("MW"), AC.

v. **Annual Delivery Specifications:** Delivered energy volumes shall be limited to the noted, annual open position for Bucket 1 resources. Maximum annual deliveries for proposed deliveries after the 2020 calendar year may not exceed specified volumes for Bucket 1 resources identified for the 2020 calendar year in the above table.

vi. **Initial Date of Delivery:** No sooner than January 1, 2018.

vii. **Term of Agreement:** Not less than two (2) years, commencing on the Initial Date of Delivery; not more than twenty five (25) years, commencing on the Initial Date of Delivery.

viii. **Proposed Pricing:** Each response must propose a single, flat price for each MWh of electric energy delivered from the proposed resource. This energy price shall remain constant throughout the entire contract term and shall not be adjusted by periodic escalators or time of delivery adjustments. This energy price shall include procurement of the energy commodity, all Green Attributes/Renewable Energy Credits related thereto, Capacity Attributes (if available), transmission charges to the delivery point, including but not limited to CAISO imbalance costs, fees and penalties as well as scheduling fees associated with delivered energy volumes. Alternative pricing options may be proposed so long as the aforementioned single flat pricing requirement has been satisfied.

ix. **Point of Delivery:** Respondents may propose product delivery under one of the following options:

1. Respondent shall be financially and operationally responsible for delivery of all electric energy to the NP15 trading hub, as defined by the CAISO [TH_NP15_GEN- APND]. Respondent shall serve as its own scheduling coordinator or make arrangements for a third party scheduling coordinator at no cost to MCE.
2. Respondent shall be financially and operationally responsible for delivery of all electric energy to the generator's applicable production node. MCE shall serve as its own scheduling coordinator, or make arrangements for a third party scheduling coordinator at MCE's sole expense, scheduling all electric energy from the generator's applicable production node.

x. **Minimum Development Progress:** Documentation substantiating achievement of the following development milestones must be provided by respondent for each eligible generator proposed under the Open Season: 1) evidence of site control; and 2) evidence that respondent has submitted a generator interconnection application to the appropriate jurisdictional entity; provided, however, that if respondent has completed interconnection studies or executed an interconnection agreement, as applicable, respondent should provide copies of such materials, including applicable appendices. Such documentation must be provided to MCE at the time of Template submittal.

B. Portfolio Content Category 2 ("Bucket 2") Eligible Renewable Energy meeting the

following criteria

i. **Resource Location:** Western Electricity Coordinating Council ("WECC").

ii. **Product:** Electric energy and related Green Attributes/Renewable Energy Credits. All deliveries must meet minimum specifications for Bucket 2 resources, which are described in the Code and applicable regulations.

iii. **Generating Capacity:** Minimum one (1) MW, AC.

iv. **Annual Delivery Specifications:** Delivered energy volumes shall be limited to the noted, annual open position for Bucket 2 resources. Maximum annual deliveries for proposed deliveries extending beyond the 2020 calendar year may not exceed the specified volume for Bucket 2 resources identified for the 2020 calendar year in the above table.

v. **Initial Date of Delivery:** No sooner than April 1, 2014.

vi. **Term of Agreement:** Not less than one (1) year, commencing on the Initial Date of Delivery; not more than three (3) years, commencing on the Initial Date of Delivery.

vii. **Proposed Pricing:** Each respondent shall propose a single, flat price for each megawatt-hour of electric energy produced by the proposed resource. This energy price shall remain constant throughout the entire contract term and shall not be adjusted by periodic escalators or time of delivery adjustments. This energy price shall include procurement of the energy commodity, all Green Attributes/Renewable Energy Credits, Capacity Attributes (if available), transmission charges to the delivery point, including but not limited to CAISO imbalance costs, fees and penalties as well as scheduling fees associated with delivered energy volumes. Respondents may propose alternative pricing options so long as the aforementioned pricing requirement has been satisfied.

viii. **Point of Delivery:** Each respondent shall be financially and operationally responsible for delivery of all electric energy to the NP15 trading hub, as defined by the CAISO [TH_NP15_GEN-APND]. Each respondent shall serve as its own scheduling coordinator or make arrangements for a third party scheduling coordinator at no cost to MCE.

ix. **Minimum Development Progress:** Documentation substantiating achievement of the following development milestones must be provided by respondent for each eligible generator proposed under the Open Season: 1) evidence of site control; and 2) evidence of a completed generator interconnection application, including the date of intended (or actual) submittal to the appropriate jurisdictional entity. Such documentation must be provided to MCE at the time of Template submittal.

5) Transfer of Environmental Attributes/Renewable Energy Certificates: As part of the proposed transaction, all Environmental Attributes/Renewable Energy Certificates must be tendered and transferred to MCE via the Western Renewable Energy Generation

Information System ("WREGIS"), or its successor, without any additional costs or conditions to MCE.

6) Acceptance of MCE's Standard Contract Terms: Each respondent shall review the terms and conditions included in MCE's standard power purchase agreement for RE (the "PPA"). Any requested changes to the PPA must be included electronically, in redline form, as an attachment to the response. Respondents should be aware that MCE will not accept or discuss changes that impose credit requirements (not already reflected in the document) on MCE or its member municipalities. Inclusion of such requested changes in any response shall be grounds for disqualification/rejection. If no changes are requested, respondent must include a statement indicating acceptance of MCE's standard contract terms. ***Note: Changes noted after response submittal may result in response disqualification/rejection.*** MCE will post its PPA on the MCE website (http://marinCleanEnergy.org/energy-procurement) and will require respondents to independently access and download this document prior to response preparation.

7) Open Season Schedule: The Open Season will be administered based on the following schedule:

- **A. Deadline for response submittal:** only electronic submittals will be accepted; such submittals must be received by MCE no later than 5:00 P.M. on Monday, March 3rd, 2014. All responses should be submitted to Greg Brehm at procurement@MarinEnergy.com and must include the following subject line: Response to MCE 2014 Open Season.
- **B. Supplier interviews/Q&A:** between March 3rd and May 31st, MCE may submit clarifying questions to certain respondents or conduct interviews, as necessary, based on information provided in the Templates. MCE shall have the right, at its sole discretion, to request information without notifying other respondents. MCE shall establish due dates for responses at the time of each request.
- **C. Response evaluation and supplier notification:** By June 2nd, MCE will notify all suppliers regarding its intent to pursue contract negotiations.
- **D. Contract approval and execution:** no later than December 31st of each calendar year.

8) Evaluation of Responses: MCE will evaluate responses against a common set of criteria that will include various factors. A partial list of factors to be considered during MCE's evaluative process is included below. This list may be revised at MCE's sole discretion.

- **A.** Project location & local benefits (Including local hiring and prevailing wage consideration)
- **B.** Interconnection status, including queue position, full deliverability of RA capacity, and related study completion
- **C.** Siting, zoning, permitting status

D. Price
E. Resource type & proposed product i.e., Bucket 1, Bucket 2 (PCC1, PCC2), etc.
F. Qualifications of project team
G. Ownership structure
H. Environmental impacts and related mitigation requirements
I. Financing plan & financial stability of project owner/developer
J. Acceptance of MCE's standard contract terms
K. Development milestone schedule

9) MCE Local Hire and Prevailing Wages: Consistent with the California Public Utilities Commission policy objectives of Decision 10-04-052, Marin Clean Energy wishes to collect information from respondents regarding past, current and/or planned efforts by project developers and their contractors to:

- Employ C-10 licensed contractors and certified electricians.
- Pay the prevailing wage for electricians pursuant to the Labor Code.
- Utilize local apprentices during construction and maintenance.
- Pay workers the correct prevailing wage rates for each craft, classification and type of work performed.
- Utilize Project Labor Agreements on the proposed project or prior project developments.
- Display a poster at jobsites informing workers of prevailing wage requirements.
- Provide workers compensation coverage.

This information will be used to evaluate potential workforce impacts of proposed projects with the goal of promoting fair worker treatment and support of the existing wage base in local communities where contracted projects will be located.

10) MCE Legal Obligations: MCE is required to comply with the Public Records Act as it relates to the treatment of any information marked "confidential." MCE is not obligated to respond to any offer submitted as part of the Open Season.

11) Shortlist Deposit: Following supplier notification (i.e., shortlist selection), which is expected to occur by June 30th (as noted above in Section 7), the selected respondent(s) will be required to submit a Shortlist Deposit of $3.00 per kilowatt of project capacity for each shortlisted generating project(s) within 10 business days of such notification. The Shortlist Deposit is generally intended to secure the obligations of any shortlisted respondent(s) during the negotiating period and to insure that each offer has been carefully considered. The Shortlist Deposit must be in the form of either a cash deposit or a Letter of Credit. "Letter of Credit" means an irrevocable standby letter of credit, in a form reasonably acceptable to MCE, issued either by (i) a U.S. commercial bank, or (ii) a U.S. branch of a foreign commercial bank that meets the following conditions: (A) it has sufficient assets in the U.S. as determined by

MCE, and (B) it is acceptable to MCE in its sole discretion. The issuing bank must have a Credit Rating of at least A- from S&P or A3 from Moody's, with a stable outlook designation. In the event the issuer is rated by both rating agencies and the ratings are not equivalent then the lower rating will apply. All costs of the Letter of Credit shall be borne by respondent. The Letter of Credit should be sent by overnight delivery to:

MCE Marin Clean Energy
781 Lincoln Avenue, St. 320
San Rafael, CA 94901

The Shortlist Deposit will be returned to respondent under one or more of the following conditions: 1) following execution of a PPA and posting of required collateral; 2) MCE's rejection of the respondent's offer following shortlist selection; 3) failure of MCE and the shortlisted respondent to agree on terms of the offer or PPA; or 4) MCE's termination of the Open Season process. Respondent will forfeit its deposit if: 1) material misrepresentations of information related to respondent's offer are identified during the negotiating process; 2) respondent fails to comply with the terms and conditions of this Open Season process; 3) respondent unilaterally withdraws the offer or attempts to materially modify the terms of its offer during the ninety-day (90-day) period immediately following supplier's acceptance of shortlist status. In addition, MCE shall be able to retain any Letter of Credit provided as a Shortlist Deposit as security under any executed PPA resulting from the Open Season process in the event that respondent fails to provide required security in accordance with the terms of such PPA.

APPENDIX C – MEA 2014 STANDARIZED RENEWABLE ENERGY TEMPLATE[170]

MCE - Marin Clean Energy - Open Season Response Template (PCC1 and PCC2 Renewable Energy), version 3.0

The Marin Clean Energy ("MCE") has established an ongoing, annual Open Season procurement process ("Open Season"). The Open Season provides a competitive, objectively administered opportunity for qualified suppliers/developers of various renewable energy products and projects to serve the energy requirements of Marin Clean Energy customers. This Response Template may not be modified and must be completed in its entirety based on instructions provided herein. **Select specific data entry cells for additional information/instructions that will be helpful in completing this template.** For additional information related to MCE's Open Season Procurement Process, please visit: www.mceClean energy.org/energy-procurement.

Renewable Energy Project information (Please create a copy of this tab for each proposed renewable energy project/transaction)

General Information:	
Organization Name:	
Open Season Cycle:	March 3rd, 2014
Portfolio Content Category Eligibility:	PCC 1 ("Bucket 1")
Project Information:	
Project Name:	
Project Address:	
Street Address 1:	
Street Address 2:	
City:	
State:	California
Zip Code:	
Project County:	
Latitude in Decimal Degrees:	
Longitude in Decimal Degrees:	
Fuel Source:	
CA RPS Cert# (or pre-cert#):	

170 http://marincleanenergy.org/energy-procurement, retrieved August 15, 2014

Proposed Capacity - Min (MW, AC):												
Proposed Capacity - Max (MW, AC):												
Annual Capacity degradation:												
Proposed Annual Energy Deliveries (Approx. MWh):												
Estimated Monthly Energy Production (MWh, Year 1):	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Plant service life (Years):												
Proposed Term (2-year minimum):												
Product (Unit contingent firm capacity and energy; firmed/shaped energy; as-available):												
Price ($/MWh) and Commercial Operation Date(s):	**COD #1**	**COD #2**	**COD #3**	**COD #4**	**COD #5**	**COD #6**	**COD #7**	**COD #8**	**COD #9**	**COD #10**	**COD #11**	**COD #12**
Proposed COD Options:												
Levelized Energy Price ($/MWh):												
Alternative Price Options:												
Project Ownership:												
Ownership Structure (Single entity, multiple):												
Owner 1:												
Owner 2:												
Owner 3:												
Ownership Shares (if multiple owners):												
Ownership share 1:												
Ownership share 2:												
Ownership share 3:												

Other Information:		
Purchase/buyout option:		
Describe purchase/buyout option:		
Re-Power Project?		
For Re-Power: Engineering Cert?		
Use of Project Labor Agreements/ Prevailing wages		Please provide specific detail on why or why not
Contact Information:		
Contact Name 1:		
Contact Title 1:		
Contact Email 1:		
Contact Phone 1:		
Contact Address 1:		
Contact Name 2:		
Contact Title 2:		
Contact Email 2:		
Contact Phone 2:		
Contact Address 2:		
Website:		
Financial Information:		
Years in business:		
Financing plan (attach):	Attach financing plan.	
Use of financial incentives (describe):		
Credit Rating, if available:		
Guarantor, if applicable:		
Financial statements - most recent two years plus recent quarterly (attach):	Attach financial statements - most recent two years.	

Current Development Status/Site Information:	
Interconnection status: provide queue position, completed studies (System Impact Study, Facilities Study, CAISO Full Deliverability Study), Interconnection level of the proposed generator (Distribution or Transmission), Scheduled Commercial Operation Date and progress related to any applicable agreement (such as an SGIA):	
Permits required for construction and operation (Conditional Use Permit, Notice of Determination, Environmental Impact Report) and status of each:	
List all known environmental issues on the project site:	
Project timeline (attach):	Attach project timeline.
Point of Interconnection (Pnode):	
Make and model of proposed generation equipment:	Attach documentation noting the make and model of proposed generation equipment.
Equipment procurement status and plan:	
Form of Site Control (attach supporting documentation):	Attach documentation substantiating site control.
Site Plan and project layout (attach):	Attach site plan and the proposed project layout.
Current site use and Zoning:	Attach a copy of the site zoning including allowable uses.
Delivery Point (NP 15 Trading Hub):	NP 15 Trading Hub

Development Experience:	
Years experience developing RE projects:	
Number of RE projects completed with past 5 years:	
Total RE capacity developed w/in past 5 years:	
List RE project #1:	
List RE project #2:	
List RE project #3:	
List RE project #4:	
List RE project #5:	
Customer References:	
Customer reference #1:	
Customer reference #2:	
Customer reference #3:	
Additional Information:	
Parent (Legal Entity type & DUNS #):	
Org chart (attach):	Attach org chart.
Current in bankruptcy:	
Bankruptcy w/in past 5 years:	
Criminal issues:	
Disputes:	
Project in negotiations w/other party:	