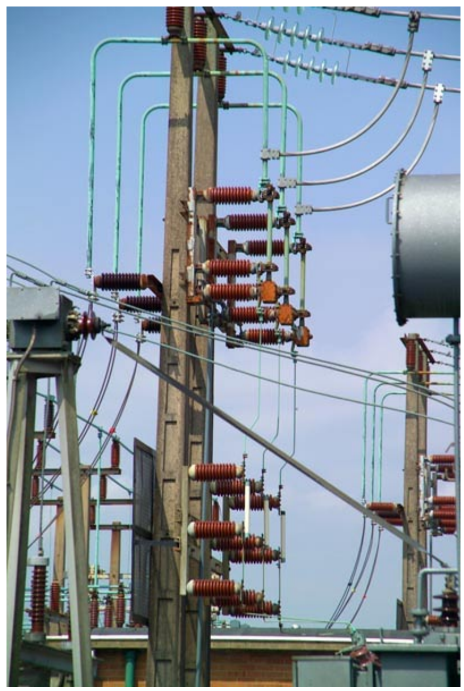
THE ECONOMICS OF COMMUNITY CHOICE AGGREGATION

The Municipalization of Local Power Acquisition and Production



Bay Area Economic Forum

A Partnership of the Bay Area Council and the Association of Bay Area Governments

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The Bay Area Economic Forum

The Bay Area Economic Forum is a public-private partnership of business, government, university, labor and community leaders that develops and implements projects that support the vitality and competitiveness of the state and regional economies, and enhance the quality of life of their residents. Sponsored by the Bay Area Council, a business organization of more than 250 CEOs and major employers, and the Association of Bay Area Governments, representing the region’s nine counties and 101 cities, the Bay Area Economic Forum produces economic policy analyses and provides a shared platform for leaders to act on key issues affecting the future of the Bay Area economy.

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Introduction

Community Choice Aggregation (CCA) is a program established by the California Legislature in 2002 (AB 117) that authorizes local public agencies to aggregate the electricity loads of residents, businesses and municipal facilities under its local jurisdiction, and to take over (municipalize) the power acquisition function currently performed by the investor-owned electric utility company (IOU) for those customers. Community Aggregators or CCAs have the options of supplying power through wholesale purchase contracts and spot market purchases and/or through ownership and operation of generating plants. However, the responsibility for all aspects of power delivery (transmission, distribution, metering, billing, and customer service) remains with the utility.

Proponents of forming CCAs assert opportunities to reduce electric bills, gain greater local control of energy supply decisions, obtain better rate stability, achieve environmental goals, plus an extensive list of other benefits for CCA customers.[1] Several California communities have examined CCA opportunities to the extent of commissioning consultant feasibility studies, and one community has developed an Implementation Plan that has been submitted to, and was recently approved by, the California Public Utilities Commission.[2] The consultant reports have provided forecasts of relative CCA/IOU rates associated with varying assumptions about the potential performance of CCAs versus utilities in purchasing power from the competitive forward and spot electricity markets, and the potential for CCAs to obtain lower production costs from CCA owned generation relative to utility owned generation. However, given the volatility of energy markets, the imperfections in energy market models, the potential for considerable variability in forecasting assumptions and the long-term commitments involved in energy procurement,

[1] See for example, ***Community Choice Aggregation Plan,*** City and County of San Francisco, April 17, 2007 and, ***Base Case Feasibility Evaluation-Marin County,*** Navigant, March 2005

[2] The San Joaquin Valley Power Authority, ***Community Aggregation Implementation Plan and Statement of Interest*** has been approved by the CPUC.

communities should carefully examine the foundations of the forecasts and the potential risks associated with adopting a CCA strategy.

The purpose of this report is to provide a frame of reference for examining the economics of CCA implementation (by California communities) that relies less heavily on forecasts of volatile market prices and power trading results. This is the third in a series of reports by the Bay Area Economic Forum dealing with economic issues surrounding the municipaliziation of electric power systems, and the seventh in a series focusing on power market issues in the wake of California's 2001 electricity crisis. **The focus of this report is on the issue of whether the implementation of CCAs in Northern California can be expected to reliably reduce electricity costs to local electricity consumers**. It sets out a simple model and shows broad measures for comparing and benchmarking CCA power costs against those of an incumbent utility, and provides approximate numerical benchmarks for CCA generation costs that would equate Northern California CCA costs to PG&E's. It also summarizes generation cost estimates for traditional and emerging technologies that have been referenced as potential sources for CCA power supply in prior CCA feasibility studies, and relates those costs to the estimated benchmarks.

This report does not attempt to address political and environmental considerations associated with local control of power supply that may be accomplished through CCAs, except to the extent that generation choices based on environmental criteria have an effect on the cost of electricity. The focus on economics is critical because it is most likely that the economic viability of a CCA is a precondition to its ability to accomplish environmental and other goals. While communities have the option of subsidizing a CCA as a good cause even if the economics do not pan out, few communities appear to have excess funds to do so.

The first section of the report reviews the key elements of the CCA enabling legislation, CPUC implementation rules, tax laws and capital structure.

The next section develops a Comparative Cost Model. As was the case in the Forum's prior two reports on the economics of municipalization, the analytic framework employed is a comparative model of system average rates (SARs) based on the conventional cost-of-service equations for investor-owned utilities, and for public utilities. Simple algebraic manipulation of the cost-of-service equations provides insights on CCA/IOU relative power costs without reliance on uncertain electric rate or market price forecasts.

The third section applies estimates of PG&E retained generation production data and develops CCA production cost benchmarks for Northern California.

The fourth section utilizes California Energy Commission (CEC) power production analyses for various emerging technologies to examine generation plant development options for CCAs.

The fifth section discusses conclusions and recommendations for CCA development strategies.

The report reaches two key conclusions. First, a new CCA cannot reliably compete on average rates while purchasing all of its power supply in the competitive wholesale market. And, second, the CCA's ability to compete rests with its success in using its tax advantage in financing to develop, own and operate cost-competitive, capital-intensive generating capacity.

The implication of these conclusions is that communities considering CCAs should first develop detailed resource plans, commit to the necessary facility siting, finance and development decisions, and bring those generating facilities on-line before transferring customers to CCA service, to avoid unnecessary subsidies from taxpayers. Absent such steps, there is significant risk that the rates paid by CCA customers will be higher than those charged by the utility.

Background

Key Elements of AB117 and CPUC CCA Implementation Rules

As a precondition for establishing CCAs, AB 117 charged the California Public Utilities Commission (CPUC) with responsibility for establishing utility cost recovery mechanisms that avoid cost shifting to utility bundled customers when CCAs begin operation, for developing transition/customer transfer rules, and for reviewing and certifying CCA implementation plans proposed by local agencies. The CPUC held a sequence of proceedings which resulted in Decision 04-12-046 (December 16, 2004), Decision 05-12-041 (December 5, 2005), Decision 07-01-025 (January 2007), and Decision 07-05-005. The first decision dealt with program implementation and transaction costs, ratemaking for utility services to CCAs, and the setting of Cost Responsibility Surcharges (CRS) to be collected from CCA served customers in order to cover the costs of utility procurement service. The second decision set rules for CCA transition and implementation, reentry/switching fees, CARE discounts, and vintaging of the CRS. Vintaging means that the CRS for each CCA will be revised according to utility above-market commitments that are in effect at the time the CCA is implemented. The third decision modified the rules for calculating the CRS, and the forth decision allowed for the carryover of some indifference credits (described below) to reduce future CRS charges.

Cost Responsibility Allocation

To prevent the shifting of utility cost obligations from CCA customers to bundled customers, the CPUC has established the CCA CRS, which consists of two non-bypassable charges, the Competitive Transition Charge (CTC) and the Power Charge Indifference Adjustment (PCIA). The CCA CRS is currently set at 2 cents/KWh and must be paid by all CCA customers on all electric usage. The CCA CRS charge is intended to cover the CCA customers' share of above-market costs that may have been incurred or committed to by the utility, for serving customers prior to the date that the departing customers are transferred to the CCA. Included are conventional generation costs as well as those necessary to ensure that the utility satisfies its Renewable Portfolio Standard (RPS) obligations. These costs are imbedded in electric rates paid by bundled customers, and charging the CRS to departing customers is intended to make the bundled customers indifferent about customers transferring to CCAs. The CPUC will periodically review and possibly modify the CRS as the configuration of utility cost obligations changes. While there is a general expectation that the CRS will diminish over time (as the DWR contracts expire, and/or market prices move higher), new "above market" obligations could be incurred by the utilities in meeting environmental requirements (e.g., RPS) and/or other contingencies downstream. By vintaging the CRS, the CPUC left open the possibility for the CRS to change as new utility obligations are undertaken on behalf of customers who may ultimately be served by a CCA and market conditions change.

The current CRS calculation methodology is described in CPUC Decision 07-01-025 as follows: "The CCA CRS is calculated in two steps. First, the Competition Transition Charge (CTC) is calculated according to Section367 (a) and is reviewed and approved in each utility's annual Energy Resource Recovery Account (ERRA) proceeding. The 'indifference rate' is then calculated by estimating the difference between the average cost of the utility's total portfolio compared to the market price benchmark. The deduction of the CTC from the indifference rate leaves as a residual the Power Charge Indifference Adjustment (PCIA) which is a component of the CRS." This methodology allows some of the benefits of utility retained generation to be transferred to CCA customers through a negative PCIA offsetting a positive CTC, reducing the CRS charges. However, the CRS cannot become negative, so to the extent that the benefits of retained generation exceed the CTC, such benefits will be retained by the bundled customers. Should indifference rates become negative (due to high market prices versus total portfolio costs), then CPUC Decision 07-05-007 allows any negative balances to be brought forward to offset any future CRS charges. Also, recent filings by PG&E (*2008 Energy Resource Recovery Account Forecast Revenue Requirement, Ongoing*

Competition Transition Charge Forecast Revenue Requirement, and Associated costs, Chapter 7, and *Joint Statement Regarding Additional Departing Load and Split Wheeling Departing Load* , June 1, 2007) indicate that the indifference rates have been negative and are forecast to be negative for 2008. This implies that if market rates continue to be high, the CCA CRS may be zero for several years ahead. While the CCA CRS may become zero, some retained generation cost advantage may continue to be held by bundled customers as will be shown below.

Consumer Participation Options

A fundamental consumer protection stipulation of the AB 117 enabling legislation is that every customer eligible to receive CCA electric supply services must also be given the opportunity to opt-out of the CCA Program and receive bundled electric services from the utility. While all customers in a CCA area will initially be automatically enrolled in the CCA when the program is certified and initiated, they will be given 60 days from initiation of CCA service in which to opt-out without penalty. Thereafter, they can opt out and resume service from the utility under the same terms that apply to customers who return to utility service from direct access services. Under those terms, the utility can charge the CCA transaction fees for resuming bundled service (as specified on utility tariffs[3]), and require six months' notice plus an obligation to remain a bundled customer for three years. The CCA may also be entitled to impose opt-out charges on departing customers.[4] The consumer opt-out privileges create generic uncertainty in the CCA organizational structure and management that may impose unpredictable CCA costs and risks associated with load forecasting and developing contracts to initiate CCA service. The CCA must develop its supply plan, estimate revenue requirements, allocate revenue requirements by customer class, design rates, issue a binding notice of intent to serve customers in its jurisdiction, announce its rate proposal and terms of

[3] See PG&E Schedule E-CCA

[4] Two CCA plans call for charging exit fees to customers who elect to opt-out after 60 days. See ***City of San Francisco Community Aggregation Plan***, Section 5.3.2.2, and San Joaquin Valley Power Authority, ***Community Aggregation Implementation Plan and Statement of Interest***, pages 62 & 63.

service to its prospective customers –without knowing with certainty what customers it will serve.

The consumer opt-out privileges guaranteed by AB 117 also present a challenge to the planning and operation of CCAs since the CCA won't know with certainty what the scope and load profile of its customer base will be more than a month or so in advance. If the CCA enters long-term power supply contracts and/or builds generation plants, it faces the risk of stranded assets (power supply that cannot be sold for its purchase cost) when customers depart back to the utility. If instead, it makes extensive use of spot market purchases to avoid stranded assets, the CCA will be exposed to market price risk. While some of the market risk might be hedged, hedging will increase the costs of service. The bottom line is that uncertainty about the size and composition of the customer base is generic to the structure of CCAs and may lead to inefficiencies and higher costs.[5]

Some prior studies have made optimistic assumptions about the proportion of customers who may opt out of California CCA programs, but have not supported these assumptions with evidence or provided analysis of the implications of differing opt-out rates.[6] However, one study reported scenarios with differing opt-out rates and found that the opting out of large customers led to projections of poor performance by CCAs relative to PG&E's rates.[7] In light of the importance of large commercial and industrial customers to the potential success of CCAs, the process for evaluating the feasibility of CCAs would benefit from surveys or analyses about

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[5] Uncertainty of customer base has been a major argument of the IOU's in connection with direct access, and was the motivation for the requirement that customers returning to bundled service from direct access service must continue bundled service for at least 3 years.

[6] For example, Navigant assumed 100% participation in its "Base Case Feasibility Evaluation – Marin County", March 2005, and suggested a simple adjustment could be made for other opt-out rates.

[7] Altos Partners (Altos) concluded that, "Virtually all of the cases we examined that posited significant opt-out by CCSF's larger commercial and industrial electricity customers resulted in unfavorable outcomes for the CCA." **Community Choice Aggregation Draft Implementation Plan**, Chapter 4, page 7. However, Altos noted reductions in PG&E's rates due to CCA Customers opting out rather than increases in CCA rates due to uncertainty of the customer base.

the attitudes of large businesses concerning the CCA/IOU cost differential thresholds that they would tolerate before opting out. Many large customers are energy intensive, compete in global markets, must operate as efficiently as possible, and may have little flexibility for supporting the aims of CCAs if a CCA cost advantage does not materialize or cannot be sustained.[8]

The significance of large commercial and industrial customer participation in the CCA is amplified by the requirements of AB1X. AB1X specifies that IOU rates for residential electricity usage up to 130% of the baseline threshold are set at 2001 levels. By many estimates these frozen rates are well below current and projected market prices for power. Assuming that to be true, the first 130% of baseline usage must be subsidized by higher usage residential customers and non-residential customers. AB1X does not directly apply to CCAs. However, if CCAs choose to offer service to residential customers, the CCA will have to offer residential rates that are essentially capped by the IOU's (AB1X compliant) residential rate. This in turn may require a high level of CCA participation by non-residential customers to cover the subsidies so long as AB1X is in effect.[9]

IOU/CCA Relative Taxation and Capital Structure

Public entities, including CCAs, are exempt from paying federal and state income taxes as well as local property taxes. The exemption from income taxes is an advantage for CCAs, but reductions in property taxes paid to local government that are avoided through the formation of CCAs must be made up from the local citizens through other taxes if government is to be made whole. Alternatively, it is reasonable to assume for analytic purposes that the CCA will continue to pay local property taxes.

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[8] The consumer opt-out privileges could conceivably be the Achilles Heal of AB 117. Should CCA rates drift higher than IOU rates and several large customers return to IOU bundled service leaving stranded generation, CCA rates would have to rise which could prompt more customers to also opt-out, setting off a death spiral of rising rates and departing customers.

[9] AB1X is currently expected to be in effect until 2022, **AB1X Reinterpretation by CPUC**, news article on SDG&E web site.

When it comes to the development of owned generation capacity, CCAs will have a financing advantage. While IOUs use a combination of debt and equity to finance assets, municipal utilities (including CCAs) use only debt. Also, for developing CCA owned generation, CCAs can likely use tax free bonds.[10] This implies that the CCA will have a lower capital cost per dollar of generation in rate base than an IOU owning the same generation plant. It also implies that CCAs can best exploit their tax advantage by owning high capital-cost, low operating cost generation facilities such as geothermal, wind and solar.

While CCA financing may be tax exempt, it remains to be seen what impact the CCA's uncertain customer/revenue base will have on its ability to obtain bond or other debt financing under favorable terms. Should financing costs increase, the CCA could be forced to raise its rates to cover the necessary debt service.

Comparative Cost and Benchmark Models

The purpose of the comparative cost model below is to develop some general insights about the comparative generation costs of CCAs and IOUs, and to develop generation cost benchmarks for Northern California CCAs competing with PG&E's generation costs. The methodology used in the model is presented in the form of equations; its conclusions are highlighted in bold. A glossary of terms is contained in Appendix I.

The model is developed from the conventional cost-of-service equation which is a simple accounting method that tallies up the costs that comprise a utility's System Average Rate or SAR. The SAR is the broadest measure of consumer electricity costs.[11] From an historical perspective, the SAR is the total electric revenue that

[10] There are many restrictions on how tax free bonds are used. For example, they cannot be used to buy out the assets of an existing utility.

[11] The SAR is an average rate across all customer classes, each of which may pay a differing rate. While CCA and PG&E rates may be designed to give preference to one rate class or another, the best rate concept for evaluating CCA economic viability is the SAR.

an electric utility collects from its customers, divided by the total volume of electricity delivered to its customers (in megawatt-hours or MWh). From a forward looking perspective, the numerator for calculating the SAR is the total revenue required for the utility to cover its projected costs, and the denominator is a projection of electricity sales.

The foundation for the comparative cost model is the conventional cost-of-service equation that equates SAR to the sum of the utility's component costs (operating expense, depreciation, taxes and capital costs, plus other charges set by the CPUC for public purpose programs, nuclear decommissioning, competitive transition charges, DWR bond charges, reliability services, and energy cost recovery) expressed as costs per MWh. These component costs can be disaggregated and rearranged into detailed costs by function (e.g. power production, transmission, distribution, and customer service). Since CCA implementation only involves the takeover of the IOU's power supply function, the IOU side of the comparative model need only include the generation or power supply component of the IOU SAR – the generation average rate or GAR_{IOU}.[12] The GAR_{IOU} is the total cost of the electricity supply divided by the total megawatt hours of electricity supply (or total generation). This denominator differs from the denominator for the SAR by an adjustment for transmission and distribution losses. Since losses are not a factor in the cost comparisons between CCAs and IOUs, it is more convenient to set the GARs up in terms of total megawatt hours of generation rather than total megawatt hours of sales.

By setting the analysis up in terms of average rates rather than total dollar expenditures, the comparisons developed can apply across utilities and CCAs.

[12] See ***City of San Francisco Community Aggregation Plan,*** Figure 1***,*** for a visual version of the cost-of-service equations for IOUs and CCAs.

The GAR_{IOU} is the volume-weighted average cost of power, including utility retained generation and power purchases:

$$GAR_{IOU} = SR_{IOU}*CR_{IOU} + SP_{IOU}*CP_{IOU} \qquad \textbf{\textit{EQ1}}$$

Where,

CR_{IOU} = average unit cost of power from utility owned (retained)
SR_{IOU} = retained generation share of total supply
CP_{IOU} = average unit cost of power purchased by the utility,
SP_{IOU} = IOU purchased power share of total supply, where
$SP_{IOU} + SR_{IOU} = 1$

The asterisk (*) is used as the symbol for multiplication

The two terms of EQ1 are the cost contributions of retained generation and of power purchases to the average cost of the IOU power supply.

For example, if an IOU generates 60% of its power supply at an average cost of $45 per MWh, and purchases 40% from the wholesale market at $60 per MWh, then

$$GAR_{IOU} = .6 * 45 + .4 * 60 = \$51$$

Power purchasers have sometimes entered into long-term contracts that later turned out to be more expensive than the power that the utility could buy in the wholesale market. An example would be the DWR contracts that were entered into by the State during California's power crisis and later allocated to California utilities. For most periods since the DWR contracts were signed, the cost of power purchased for California utilities, on average, cost more than it could bought for in the current wholesale market. For analysis, it is useful to decompose those costs per MWh into the wholesale market price (MP) and an over-market premium (PM). Estimating the decomposition of DWR and QF contract prices into market and over-market components has been a major task for the CPUC in attempting to determine what the CRS should be.

Substituting MP + PM for CP_{IOU} (or replacing CP_{IOU} with MP+ PM) the equation EQ1 can be expanded as follows:

$$GAR_{IOU} = SR_{IOU}*CR_{IOU} + SP_{IOU}*MP + SP_{IOU}*PM \qquad \textbf{\textit{EQ2}}$$

This equation says that the IOU average generation cost is a weighted average of retained generation costs, purchased power valued at market, and purchased power valued at the over market premium. EQ2 is the IOU Cost Model.

The GAR_{CCA} is the volume weighted average cost of power including CCA owned generation and power purchases plus the CRS, and the CCA Overhead costs per MWh (OV_{CCA}) as follows:

$$GAR_{CCA} = SO_{CCA}*CO_{CCA} + SP_{CCA}*CP_{CCA} + CRS + OV_{CCA} \qquad \textbf{\textit{EQ3}}$$

Where,

CO_{CCA} = average unit cost of power from CCA owned generation
SO_{CCA} = owned generation share of total CCA supply
CP_{CCA} = average unit cost of power purchased by the CCA
SP_{CCA} = CCA purchased power share of total supply, where $SP_{CCA} + SO_{CCA} = 1$
OV_{CCA} = CCA overhead costs per MWh

The OV_{CCA} variable is intended to cover all CCA administrative and operating costs (including power trading profits and losses, ISO charges, and utility charges to the CCA per PG&E Schedule E-CCA) and interest payments on investment required to set up the CCA, exclusive of any owned power plant costs. This overhead charge per MWh can be expected to vary in proportion to the level of the market trading activity, gains and losses from trading, and utility charges (per schedule E-CCA) related to the consumer opt-out rate. EQ3 is the CCA Cost Model.

The cost per MWh differential between CCAs and IOUs is the difference in GARs, GAR_{CCA} - GAR_{IOU} =,

$$SO_{CCA}*CO_{CCA}+SP_{CCA}*CP_{CCA}+CRS+OV_{CCA}$$
$$- \ (SR_{IOU}*CR_{IOU} + SP_{IOU}*MP + SP_{IOU}*PM) \qquad \textbf{\textit{EQ4}}$$

Put simply, **any new CCA will acquire incremental power in the same competitive wholesale market as will the IOU and both will pay the market price (MP)**[13].

$CP_{CCA} = MP$ ***EQ5***

Note that the IOU will continue to be burdened with the overhang of old over-market contracts and will also pay the average premium (PM) for its purchased power.

However, as specified in CPUC Decision 04-12-046, Decision 05-12-041, Decision 07-01-025, and Decision 07-05-005, the CPUC attempts to set the CRS to cover the over-market costs of utility power purchases though the setting of the CTC and the PCIA rates as described above. The CTC is calculated and set for a subset of contracts while the PCIA is derived as a residual by subtracting the CTC from the total portfolio indifference charge. In effect, the sum of the CTC and the PCIA rates are approximately equal to the utility generation average rate less the market price benchmark[14] or

$CRS = PCIA + CTC = GAR_{IOU} – MP$ ***EQ6***

The CPUC Rules also constrain the CRS to be non-negative. A positive CRS will generally be the result of sufficiently high IOU power purchase contract costs (or a high premium over market) to bring up the weighted average portfolio costs (that include lower cost retained generation) to the point of exceeding the market price benchmark, yielding a positive "indifference rate". On the other hand, a zero CRS will be the result of the IOU total portfolio costs being lower than the market price (implying a negative premium over market) such that the indifference rate becomes non-positive, causing the CRS to be set to zero. Given these two possible

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[13] It could be argued that it is possible for a CCA or PG&E to outperform the other in electricity trading. While both face the same prices, one could conceivably do better in the mix of spot, medium term and long-term contracts, and in the size of blocks purchased. However, to count on such an outcome is speculative.

[14] This approximation ignores the inclusion of some very small franchise fees.

outcomes for the CRS, evaluation of the potential rate differences between IOUs and new CCAs requires analysis under both a positive CRS and a zero CRS.

Substituting EQ5 and EQ6 into EQ4, yields the following equation for situations where CRS is positive,

$GAR_{CCA} - GAR_{IOU} =$,

$SO_{CCA}*CO_{CCA}+SP_{CCA}*MP+ (GAR_{IOU} – MP) +OV_{CCA} - GAR_{IOU} =$

$SO_{CCA}*CO_{CCA}+SP_{CCA}*MP + OV_{CCA} – MP$ ***EQ7***

This equation implies that the CCA vs IOU rate differential is the weighted average cost of CCA generated power and purchased power plus the per unit cost of CCA overhead, less the market price of power. Under the current methodology for calculating the CRS, when the CRS is positive, the utility retained generation cost advantage is spread equally across all customers, and the CCA average total costs must not exceed market rates if they are to match or beat the utility rates. This can only be accomplished by producing power in owned plants at costs below market rates.

However, in the cases where the market price exceeds the utility generation average rate and the CRS is 0, then EQ7 is resolved as follows:

$GAR_{CCA} - GAR_{IOU} =$

$SO_{CCA}*CO_{CCA}+SP_{CCA}*MP+ OV_{CCA} - GAR_{IOU}$ *where CRS = 0* ***EQ7A***

Equations EQ7 and EQ7A comprise the Comparative Cost Model

Equation EQ7A implies that the CCA vs IOU rate differential is the weighted average cost of CCA generated power and purchased power plus the per unit cost of CCA overhead, less the utility generation average rate, (which by assumption is less than the market price). Under the current methodology for calculating the

CRS, the utility retained generation cost advantage is spread equally across all customers only to the point of 0 CRS and then all additional utility cost advantage is retained by bundled customers. In that case, the CCA average total costs (for generation, purchases and overhead) must not exceed the utility's generation average rate (GAR_{IOU}) for the CCA to match or beat the utility rates.

Some additional perspective on the impact of higher market prices on the CCA/IOU rate differential can be obtained by expanding EQ7A, using EQ2 as follows:

$GAR_{CCA} - GAR_{IOU} =$

$(SO_{CCA}*CO_{CCA} - SR_{IOU}*CR_{IOU}) + (SP_{CCA} - SP_{IOU})*MP - SP_{IOU}*PM + OV_{CCA}$

where CRS = 0 **_EQ7B_**

This form of the Comparative Model shows that the CCA/IOU rate differential will be determined by the difference between CCA and the IOU's production costs, the relative shares of power supply purchased in the market by the CCA vs the IOU, the market premium paid by the IOU on its contracts (which is negative when the CRS = 0)[15] , and the CCA overhead.

Should CCAs begin operation before they have in place operating generation plants, they will be dependent on market purchases for the first three to five years. To examine the potential relative rate implications of CCA market purchases during this period, set $SO_{CCA} = 0$ and $SP_{CCA} = 1$ and substitute these values into EQ7 and EQ7A, which yields the following. If CRS is positive, then,

$GAR_{CCA} - GAR_{IOU} = OV_{CCA}$ **_EQ8_**

The rate differential in this case, is the per unit average cost of the CCA's overhead. And, if the CRS is 0 then,

$GAR_{CCA} - GAR_{IOU} = OV_{CCA} + MP - GAR_{IOU}$ **_EQ8A_**

[15] It may be possible for the market premium to be positive while the CRS=0, in the event of low then current market prices and prior year carryover in the PCIA balancing account.

The rate differential in this case, is the per unit average cost of the CCA's overhead plus the differential between the market price and the IOU's generation average rate.

Equations EQ8 and EQ8A imply that **if the CCA purchases 100% of its power supply from the competitive market, the CCA cannot avoid higher average rates than the utility unless it subsidizes rates (or somehow wins the gamble of "beating the market").**

It should also be noted that the only term of EQ8 and EQ8A that can be controlled by the CCA is its overhead ($OV_{CCA)}$ and, its overhead cost can be affected by the customer opt-out rate. In other words**, the CCA's rates relative to the IOU's rates will be mostly determined by forces outside the CCAs control so long as the CCA is dependent only on market purchases for its supply.**

It is apparent from these equations that **for a CCA to have the potential to match or beat the power supply costs of the utility, the CCA must exploit its tax advantage by building, owning and operating cost-competitive generating capacity**. If it does build, own and operate new plants then what must the average production costs of those plants be in order to match the incumbent IOU's average power production costs? The Comparative Cost Model can be rearranged to calculate cost benchmarks for the CCA by setting EQ7 and EQ7A to 0 and solving for the CCA average owned production cost (CO_{CCA}).

This exercise yields the following (for SO_{CCA} greater than 0):

When CRS is positive, then

$$CO_{CCA} = MP - OV_{CCA}/SO_{CCA} \qquad \textbf{\textit{EQ9}}$$

And, when CRS = 0, then

$$CO_{CCA} = [GAR_{IOU} - SP_{CCA}*MP - OV_{CCA}]/SO_{CCA} \qquad \textbf{\textit{EQ9 A}}$$

Alternatively, this equation can be expanded using EQ 2 to express the benchmark in terms of market rates and premium over market costs.

$CO_{CCA} = [SR_{IOU}*CR_{IOU} + (SP_{IOU} - SP_{CCA})*MP + SP_{IOU}*PM - OV_{CCA}]/SO_{CCA}$ ***EQ9B***

EQ9 and EQ9A comprise the Benchmark Model. The model specifies the target maximum (or benchmark) average cost for CCA-owned power production that will allow the CCA to match the IOU's generation average rates.

For periods when the CRS is positive, EQ9 implies that the CCA must meet the market price less a multiple ($1/SO_{CCA}$) of its average per unit overhead costs to match the IOU average rate. Note that the if the CCA produces 1/3 of its power then its production cost benchmark equals the market price less 3 times its average per MWh overhead cost.

For periods when the CRS is 0, then EQ9A implies that the CCA must meet a multiple of the difference between IOU's generation average rate and the CCA's average cost of market purchases, less the CCA's per unit overhead costs to match the IOU average rates.

The algebraic operations with the cost-of-service equations that have been performed above, show that **the economic viability of a new CCA depends primarily on the potential for the CCA to develop cost-competitive owned generating capacity. Until such time as a CCA can utilize its tax advantage by developing and bringing on-line generating resources that meet or exceed the cost benchmark criteria of EQ9 and EQ9A, the CCA will have to collect higher rates (than the utility) from its customers or finance subsidies. This suggests that the first stage of CCA feasibility studies should be focused on precisely how, where and when the prospective CCA can site, build, and operate efficient generating facilities, and what the operating characteristics and generation costs of those specific plants will likely be.**

In spite of the critical importance of plant-specific operational and cost data to the economic viability of CCAs, such data is conspicuously absent from most of the CCA plans being proposed to Northern California communities.[16] Unless the proposed CCA can verify that the operating characteristics are consistent with the load requirements of the community and that the costs of specific plant technologies built out at specific sites meet or exceed the appropriate benchmarks against the incumbent IOU's costs, the community will lack the economic information it needs to decide whether to invest in the CCA or for consumers to consider remaining in a CCA.[17]

From a long-term perspective, to the extent that the CCA is able to develop owned sources of renewable power, and secure a higher proportion of its energy supply from renewable power than renewables secured by the utility, it may be able to reduce its exposure to the political and market risk associated with hydrocarbon fuels, yielding unspecified cost advantages. Though speculative, other benefits may accrue if in the future the federal government were to implement a carbon tax.

The comparative cost and benchmarking discussion in this section has focused on general cost relationships that can be extracted from conventional cost-of-service

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[16] The San Joaquin Plan appears to be the exception, having identified a specific plant location and technology and is preparing to file with the CEC Siting Division for a license to build. The San Francisco Plan refers to a " 360 MW Roll Out" consisting of conservation, fuel cells, solar and wind generation but provides no data concerning how or where any specific plants will be sited or what their production levels or costs will be. The Navigant Marin County Report lists a portfolio of plant technologies and cost figures for wind, geothermal, and gas, absent specifics on how or where the plants would be sited.

[17] The need for site specific plant information was provided by the CEC in its frequently quoted report on generic plant costs as follows: "This Report is intended to provide a basic understanding of some of the fundamental attributes that are generally considered when evaluating the cost of building and operating different electricity generation technology resources. But these costs do not reflect the total costs to consumers of adding these technologies to a resource portfolio. The technology costs in this report are non site-specific. If a developer builds a specific plant at a specific location, the cost of siting that plant at that specific location must be considered. Some projects may require radial transmission additions, fuel delivery, system upgrades or environmental mitigation expenses" ***Comparative Cost of California Central Station Electricity Generating Technologies***, CEC, June 5 2003.

equations. The following section develops numerical estimates of PG&E's retained generation average rates and uses those estimates with the Benchmark Model to develop numerical benchmarks for prospective Northern California CCAs.

Northern California CCA Cost Benchmarks Against PG&E Retained Generation Costs

Proposed CCAs for Northern California communities would take over the power supply function of Pacific Gas and Electric Company within the community's boundaries. Therefore, PG&E's retained generation[18] costs are a key factor in determining the cost thresholds that the CCA must meet to be economically viable. This section describes PG&E's retained generation capacity for nuclear, hydro, and steam plant types, presents estimates of numerical generation costs for each plant type and for the average across all plants, and develops numerical average production cost benchmarks for CCA owned generation that would be required to match PG&E's generation rates.

PG&E's 2006 FERC Form 1 Annual Report shows that the utility's retained generation accounted for 36% of the utility's total power supply. The composition of the retained generation was approximately 20% nuclear, 15.5 % hydro, and 0.5% gas fired steam.[19] To develop numerical benchmarks for CCA production costs, forecasts of PG&E's nuclear, hydro and steam production costs are required.

Nuclear Production Cost

In 2006, Diablo Canyon produced 18,390,997 MWh of electricity, running at a capacity factor of 93%. Having very low operating cost, and a nearly depreciated rate base, Diablo Canyon has been producing very low-cost power. However,

[18] Retained generation refers to the fleet of power plants that were not sold by PG&E during the period of electric industry restructuring that required plant divestiture by investor owned utilities.
[19] 2006 FERC Form 1, page 401a

PG&E has now scheduled the replacement of its generators in 2008 and 2009 at a cost of about $706 million. This will substantially increase the rate base, depreciation expense, capital cost and tax allocations for Diablo Canyon production. While Diablo Canyon costs will be increasing, the CPUC has approved the generation replacement project (Decision 05-11-026) agreeing that it is a low cost alternative for future power supply.

To develop a nuclear production cost projection, it was assumed that Diablo Canyon will generally operate at a capacity factor of 89% (consistent with performance in recent years), adjusted downward for outages during the periods of generator replacement and periods of refueling. Cost projections were developed using data from PG&E's FERC Form 1, and various PG&E documents filed with the CPUC in connection with the generation replacement project, from PG&E's 2007 General Rate Case documents, and from work papers obtained from PG&E. Projections of PG&E's nuclear production costs are shown in Appendix II (Table 1).

Hydro Production Cost

In 2006, PG&E's conventional hydro generators produced 14,186,653 MWh. Hydro has been a major source of inexpensive power for PG&E for many years but levels of production vary somewhat with weather conditions. During the past ten years, hydro facilities have produced an average of 12,014,457 MWh per year. This average was used to develop a forecast of hydro generation cost. Cost estimates have been developed from PG&E's FERC Form 1 and 2007 General Rate Case documents and from work papers obtained from PG&E. Projections of PG&E's hydro production costs are shown in Appendix II (Table 1).

Steam Production Cost

In 2006, PG&E generated only about one-half of one percent of its power supply from aging gas fired plants, including Hunters Point, which was permanently shut down in May 2006. Looking forward, PG&E will have minimal gas-fired generation until its new Gateway Generating Station (formerly Contra Costa Unit 8 that PG&E

took over during construction from Mirant) is brought on line in mid-to-late 2009. This unit is an efficient 530 MW combined cycle plant. For cost analysis, it is assumed that the unit will begin operation in 2010, will operate with a heat rate of 7,100 Btus per KWh, a capacity factor of 91.6%, and produce 4,252,806 MWh per year. No other future additions to PG&E's fleet of generating units have been assumed. Cost projections for this plant have been developed using data derived from various CEC staff reports and from CPUC documents related to Application 05-06-029. Projections of PG&E's steam production costs are shown in Appendix II (Table 1).

Generation Average Cost

The average production cost for PG&E's retained generation $CR_{PG\&E}$ is the volume- weighted average of the average production costs for the three plant types. Projections of $CR_{PG\&E}$ are shown in Appendix II (Table 1) for 2007 through 2024.

CCA Owned Generation Benchmarks

The projections of $CR_{PG\&E}$ can be used as an input to the Benchmark Model to calculate the maximum CCA-owned generation cost (for SO_{CCA} greater than 0) that would yield average rates that match PG&E's. The Benchmark Model with $SR_{IOU} = SR_{PG\&E}$, $CR_{IOU} = CR_{PG\&E}$ and $SP_{PG\&E} = 1 - SR_{PG\&E}$ inserted is as follows:

When CRS is positive, then

$$CO_{CCA} = MP - OV_{CCA}/SO_{CCA} \qquad \textbf{\textit{EQ9}}$$

And, when CRS = 0, then

$$CO_{CCA} = [GAR_{PG\&E} - SP_{CCA}*MP - OV_{CCA}]/SO_{CCA} \qquad \textbf{\textit{EQ9 A}}$$

Or,

$$CO_{CCA} = [SR_{PG\&E}*CR_{PG\&E}+(SP_{PG\&E}-SP_{CCA})*MP+SP_{PG\&E}*PM-OV_{CCA}]/SO_{CCA} \qquad \textbf{\textit{EQ9B}}$$

The Benchmark Model can be used for assessing the production cost challenge that prospective CCAs face in developing their resource plans. By varying assumptions about PG&E's retained generation costs, CCA overhead, market prices, and the level of owned production that is being planned, the Benchmark Model will calculate the maximum production cost that the CCA can obtain from its owned generation, to match PG&E's generation average rates. The results of some sample Benchmark Model simulations are presented on Tables 2 through 7. The first column of Tables 2 through 7 shows the years from 2007 through 2024. The second column shows PG&E's average production cost from retained generation as shown on Table 1. The third column is the assumed wholesale market price for power. The fourth column shows estimates for the premium over market of PG&E's contracted power costs. The fifth column shows the estimated level of PG&E's generation (or total portfolio) average rate. The data in the remaining 10 columns across each page beginning with column 4 are the benchmark average cost figures that the CCA must not exceed in order to match or beat PG&E's estimated GAR.

The first three tables utilized EQ9 under the assumption that for the range of market prices (MP) from $50/MWh to $60/MWh the CRS could be positive (although reported carryovers of negative PCIAs may make this assumption unlikely). When the CRS is positive, the cost benefits of PG&E's retained generation is shared by all customers so the CCA simply has to meet the market price less a multiple of the CCA's overhead. As shown above, the CCA cannot match PG&E's rates without developing efficient CCA owned generation. As shown on Table 2, line 2010, it will take a CCA average generation cost of $45 per MWh from generation covering 100% of the CCA load to offset a CCA overhead rate of $5/MWh when the market price is $50/MWh. If the CCA only covers 50% of its load under these same conditions, it would have to achieve a production cost of only $40/MWh. If the market rate is higher (say $60/MWh), as shown on Table 3, line 2010, then the efficiency target is also relaxed by $10/MWh. As shown on

Table 4, increasing the CCA overhead pushes the production efficiency target lower. At this stage, it is difficult to guess what overhead assumption would be realistic for new CCAs. For many utilities, A&G average costs will be around $6/MWh to $8/MWh. Adding to the normal A&G, the costs of utility services to the CCA, ISO charges, and net trading costs could easily put the average overhead cost of the CCA in the range o $10/MWh to $15/MWh.

Tables 5, 6 and 7 utilized EQ9A under the assumption that for the range of market prices (MP) from $70/MWh to $80/MWh the CRS would be zero**.** In light of recent PG&E reports, the carryover of negative PCIAs may make this assumption very likely to be correct. The results shown on Table 5 (under a higher market price) are very similar to those shown on Table 3 for 100% CCA load covered by owned generation. However, a smaller percent of coverage from owned generation, combined with the higher market prices yields a much lower production cost target. Comparison of Tables 6 and 7 shows the impact of increasing overhead on the production benchmarks, particularly where the CCA owned generation is less than complete.

These Tables provide numerical illustrations of the implications of the equations developed above. They essentially verify that a new CCA cannot offer lower prices than the utility unless it utilizes its financing advantage in developing competitive generating facilities to cover a high proportion of the CCAs' load. The tables show that the higher the market price, the less stringent are the production cost requirements for the CCA, but the higher the CCA overhead, the more challenging the production cost requirements.

As shown by the Benchmark Model, the competitive position of the CCA is to a large extent affected by forces outside its control - the market and the incumbent utility. The only variables in the model that the CCA can affect are its overhead and its choice of owned production. The benchmarks shown on these tables provide some thresholds for CCAs to use in targeting generation plant development**. The real issue for CCAs is to develop generation plant that will give them a sustainable cost advantage.**

CCA Generation Potential

Unless communities are willing to gamble on the notion that new CCAs can "beat the market" effectively and consistently enough to compete with PG&E, then the focus of CCA planning should be on precisely what plant technologies to build and precisely where to build them. The most likely cost advantage of a CCA is in using its financing advantage by building high capital cost, low operating cost generating plants. The technology that best fits that bill is renewable geothermal, which is included in the proposed resource portfolio of the Marin County Feasibility Study.[20] However, it is not clear where a Northern California community can find geothermal fields with adequate pressure for power generation and be able to obtain the rights for development. The only apparent sites in Northern California are near the Geysers and near the Oregon border. With the completion of the Bottle Rock facility the remaining potential close to the Bay Area will be very limited. And, given the attractiveness of geothermal in meeting requirements for renewable resources there will likely be significant competition for any feasible sites, diminishing the prospects for obtaining competitive power from this resource.

The next best technology for CCAs appears to be wind, as has been recognized in prior studies. The cost estimates for green field or generic wind generators appear to be in the ballpark of numbers that could be competitive (Navigant reported $49/MWh plus $11/MWh for backup capacity), particularly if gas prices remain high. However, where a CCA can get rights and authorization to site wind generators, and what the site specific costs will be must also be addressed. There are also limitations on the share of wind generation that can be included in a

[20] The Marin report list 29 MW of geothermal at a levelized cost of $55/MWh.(in 2005 $).

CCA's resource portfolio.   Wind generators must also be backed up by other load-following resources to supplement the uncertain wind production on an instantaneous basis.

The production costs of several emerging technologies have been studied by the California Energy Commission. Its estimates of production costs for such technologies as solar PV and fuel cells (which are included in the San Francisco Plan), are too high at present for those technologies to be considered cost-competitive. While they are likely to become more competitive over time, it has not been demonstrated that they have reached a cost-effective stage of development yet.

Conclusions

Communities considering CCAs must consider two elements of their resource portfolios: supply secured through the market, and CCA-owned generation capacity. Regarding market trading, they need to ask whether they can outperform the IOU. Regarding owned generation, to be competitive they must develop renewable or other capacity at the necessary scale.

The analyses in this report point to two key conclusions. First, if the incumbent utility owns and operates generation capacity, particularly capacity that generates below-market power, then a new CCA cannot reliably compete on average rates while purchasing all of its power supply in the competitive wholesale market. Second, the CCA's ability to compete rests with its success in using its tax advantage in financing to develop, own and operate cost-competitive, capital-intensive generating capacity. As indicated above, this may be challenging, as most renewable energy remains more expensive to generate than power from conventional sources.

Though more expensive in the short-term, loyally-owned generation from renewable sources may offer the advantage of hedging the long-term price and supply risk associated with fossil energy. The limited availability of renewable generation such as wind and geothermal, and the fact that much of that capacity will be heavily competed for by IOUs and other utilities that are also seeking to expand their renewable energy portfolios (to meet the Renewable Portfolio Standard), suggests that securing these resources may also be difficult.

The implication is that communities considering CCAs should first develop detailed resource plans that specify the types and sizes of generating capacity that will be developed to serve the community's load, where it will be sited, how it will be financed[21], and what the site-specific installed production costs will be. Once a competitive resource plan (one that meets or beats the benchmark tests of EQ9) has been developed, the community can make an informed decision on whether to proceed with the establishment of a CCA, and make the investment needed to acquire the necessary generation capacity.

Absent such a plan, there is significant risk that CCA rates will be higher than rates charged by the utility. While some customers may be willing to pay marginally higher rates in exchange for more green power, others may not, and significantly higher rates will put pressure on businesses and on residents who are larger electricity consumers to opt out, increasing the burden on customers who remain.

For communities that choose to proceed with the formation of CCAs, the first order of business should be to commit to the necessary siting decisions and expeditiously develop cost-efficient generating facilities**.** To avoid unnecessary subsidies by taxpayers, the transfer of customers from the incumbent utility should ideally take place after competitive generating plants are in operation.

[21] A determination of how the lack of a known, captive customer/revenue base will affect the financing of CCA generating facilities should be sought early in the resource planning phase of CCA development.

APPENDICES

Appendix I - Glossary of Terms

Abbreviations:

AB	Assembly Bill
CCA	Community Choice Aggregator – a local government agency
CEC	California Energy Commission
CPUC	California Public Utilities Commission
CTC	Competitive Transition Charge
IOU	Investor owned utility
DWR	California Department of Water Resources
PCIA	Power Charge Indifference Adjustment
QF	Qualifying Facility

Model Variables and Symbols

CO_{CCA}	Average cost per MWh of power from CCA owned generation
CP_{CCA}	Average cost per MWh of power purchased by the CCA
CP_{IOU}	Average cost per MWh of power purchased by the IOU
CR_{IOU}	Average cost per MWh of power from IOU retained generation
CRS	Cost Responsibility Surcharge
GAR_{CCA}	CCA Generation Average Rate
GAR_{IOU}	IOU Generation Average Rate
MP	Market Price
OV_{CCA}	CCA overhead costs per MWh
PM	Premium
SAR	Utility System Average Rate
SO_{CCA}	Owned generation share of total CCA power supply
SP_{CCA}	CCA purchased power share of total CCA power supply
SP_{IOU}	IOU purchased power share of total IOU power supply
SR_{IOU}	IOU retained generation share of IOU power total supply
*	Symbol representing multiplication

Appendix II - PG&E Generation Average Rates

TABLE 1 PG&E RETAINED GENERATION AVERAGE RATES ($/MWh)

	2007	2008	2009	2010	2011	2012	2013	2014	2015
NUCLEAR GENERATION:									
AVERAGE RATE	38.77	48.78	58.01	54.29	54.02	54.12	54.35	59.54	54.84
SHARE OF TOTAL SUPPLY (%)	19.07	17.74	16.23	18.24	17.97	17.71	17.44	16.22	16.93
HYDRO GENERATION:									
AVERAGE RATE	30.04	30.98	31.92	32.84	33.73	34.61	35.46	36.30	37.12
SHARE OF TOTAL SUPPLY	13.01	12.81	12.62	12.44	12.25	12.07	11.89	11.72	11.55
STEAM GENERATION:									
AVERAGE RATE	0.00	0.00	0.00	55.13	55.60	56.10	56.61	57.16	57.73
SHARE OF TOTAL SUPPLY	0.00	0.00	0.00	4.33	4.26	4.20	4.14	4.08	4.02
WEIGHTED AVERAGE COST OF GENERATION ($CR_{PG\&E}$):									
AVERAGE COST PER MWH	**35.23**	**41.31**	**43.43**	**46.77**	**47.00**	**47.43**	**47.92**	**50.73**	**48.90**
GENERATION SHARE OF LOAD	32.08	30.55	30.95	35.00	34.49	33.98	33.48	32.02	32.49
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
NUCLEAR GENERATION:									
AVERAGE RATE	54.06	53.93	53.74	58.91	54.20	53.10	52.79	56.76	50.94
SHARE OF TOTAL SUPPLY	16.68	16.44	16.19	15.06	15.72	15.48	15.26	14.02	14.81
HYDRO GENERATION:									
AVERAGE RATE	37.92	38.70	39.47	40.22	40.95	41.66	42.64	43.03	43.68
SHARE OF TOTAL SUPPLY	11.38	11.21	11.04	10.88	10.72	10.56	10.40	10.25	10.10
STEAM GENERATION:									
AVERAGE RATE	58.32	58.94	59.59	60.27	60.98	61.72	62.49	63.28	64.12
SHARE OF TOTAL SUPPLY	3.96	3.90	3.84	3.78	3.73	3.67	3.62	3.56	3.51
WEIGHTED AVERAGE COST OF GENERATION ($CR_{PG\&E}$):									
AVERAGE COST PER MWH	**48.85**	**49.14**	**49.39**	**52.24**	**50.33**	**50.10**	**50.38**	**52.54**	**49.99**
RETAINED GEN SHARE OF LOAD	32.01	31.54	31.07	29.72	30.16	29.72	29.28	27.83	28.42

Appendix III - CCA Benchmarks

TABLE 2
NORTHERN CALIFORNIA
CCA OWNED GENERATION COST BENCHMARKS ($/MWh)

MARKET PRICE $50/MWh, CCA OVERHEAD $5/MWh, CCA CRS POSITIVE

					MAXIMUM COST OF CCA OWNED GENERATION TO MATCH $GAR_{PG\&E}$									
					CCA % OF LOAD FROM OWNED GENERATION									
	$CR_{PG\&E}$	MP	PM	$GAR_{PG\&E}$	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
2007	35	50	8	51	0	25	33	38	40	42	43	44	44	45
2008	41	50	8	53	0	25	33	38	40	42	43	44	44	45
2009	43	50	8	53	0	25	33	38	40	42	43	44	44	45
2010	47	50	8	54	0	25	33	38	40	42	43	44	44	45
2011	47	50	8	54	0	25	33	38	40	42	43	44	44	45
2012	47	50	8	54	0	25	33	38	40	42	43	44	44	45
2013	48	50	8	55	0	25	33	38	40	42	43	44	44	45
2014	51	50	8	56	0	25	33	38	40	42	43	44	44	45
2015	49	50	8	55	0	25	33	38	40	42	43	44	44	45
2016	49	50	8	55	0	25	33	38	40	42	43	44	44	45
2017	49	50	8	55	0	25	33	38	40	42	43	44	44	45
2018	49	50	8	55	0	25	33	38	40	42	43	44	44	45
2019	52	50	8	56	0	25	33	38	40	42	43	44	44	45
2020	50	50	8	56	0	25	33	38	40	42	43	44	44	45
2021	50	50	8	56	0	25	33	38	40	42	43	44	44	45
2022	50	50	8	56	0	25	33	38	40	42	43	44	44	45
2023	53	50	8	56	0	25	33	38	40	42	43	44	44	45
2024	50	50	8	56	0	25	33	38	40	42	43	44	44	45

TABLE 3
NORTHERN CALIFORNIA
CCA OWNED GENERATION COST BENCHMARKS ($/MWh)

MARKET PRICE $60/MWh, CCA OVERHEAD $5/MWh, CCA CRS POSITIVE

					MAXIMUM COST OF CCA OWNED GENERATION TO MATCH GARPG&E									
					CCA % OF LOAD FROM OWNED GENERATION									
	CRPG&E	**MP**	**PM**	**GARPG&E**	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
2007	35	60	3	54	10	35	43	48	50	52	53	54	54	55
2008	41	60	3	56	10	35	43	48	50	52	53	54	54	55
2009	43	60	3	57	10	35	43	48	50	52	53	54	54	55
2010	47	60	3	57	10	35	43	48	50	52	53	54	54	55
2011	47	60	3	57	10	35	43	48	50	52	53	54	54	55
2012	47	60	3	58	10	35	43	48	50	52	53	54	54	55
2013	48	60	3	58	10	35	43	48	50	52	53	54	54	55
2014	51	60	3	59	10	35	43	48	50	52	53	54	54	55
2015	49	60	3	58	10	35	43	48	50	52	53	54	54	55
2016	49	60	3	58	10	35	43	48	50	52	53	54	54	55
2017	49	60	3	59	10	35	43	48	50	52	53	54	54	55
2018	49	60	3	59	10	35	43	48	50	52	53	54	54	55
2019	52	60	3	60	10	35	43	48	50	52	53	54	54	55
2020	50	60	3	59	10	35	43	48	50	52	53	54	54	55
2021	50	60	3	59	10	35	43	48	50	52	53	54	54	55
2022	50	60	3	59	10	35	43	48	50	52	53	54	54	55
2023	53	60	3	60	10	35	43	48	50	52	53	54	54	55
2024	50	60	3	59	10	35	43	48	50	52	53	54	54	55

TABLE 4
NORTHERN CALIFORNIA
CCA OWNED GENERATION COST BENCHMARKS ($/MWh)

MARKET PRICE $60/MWh, CCA OVERHEAD $10/MWh, CCA CRS POSITIVE

					MAXIMUM COST OF CCA OWNED GENERATION TO MATCH $GAR_{PG\&E}$									
					CCA % OF LOAD FROM OWNED GENERATION									
	$CR_{PG\&E}$	MP	PM	$GAR_{PG\&E}$	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
2007	35	60	3	54	0	10	27	35	40	43	46	48	49	50
2008	41	60	3	56	0	10	27	35	40	43	46	48	49	50
2009	43	60	3	57	0	10	27	35	40	43	46	48	49	50
2010	47	60	3	57	0	10	27	35	40	43	46	48	49	50
2011	47	60	3	57	0	10	27	35	40	43	46	48	49	50
2012	47	60	3	58	0	10	27	35	40	43	46	48	49	50
2013	48	60	3	58	0	10	27	35	40	43	46	48	49	50
2014	51	60	3	59	0	10	27	35	40	43	46	48	49	50
2015	49	60	3	58	0	10	27	35	40	43	46	48	49	50
2016	49	60	3	58	0	10	27	35	40	43	46	48	49	50
2017	49	60	3	59	0	10	27	35	40	43	46	48	49	50
2018	49	60	3	59	0	10	27	35	40	43	46	48	49	50
2019	52	60	3	60	0	10	27	35	40	43	46	48	49	50
2020	50	60	3	59	0	10	27	35	40	43	46	48	49	50
2021	50	60	3	59	0	10	27	35	40	43	46	48	49	50
2022	50	60	3	59	0	10	27	35	40	43	46	48	49	50
2023	53	60	3	60	0	10	27	35	40	43	46	48	49	50
2024	50	60	3	59	0	10	27	35	40	43	46	48	49	50

TABLE 5
NORTHERN CALIFORNIA
CCA OWNED GENERATION COST BENCHMARKS ($/MWh)

MARKET PRICE $70/MWh, CCA OVERHEAD $5/MWh , CCA CRS = 0

					MAXIMUM COST OF CCA OWNED GENERATION TO MATCH $GAR_{PG\&E}$									
					CCA % OF LOAD FROM OWNED GENERATION									
	$CR_{PG\&E}$	MP	PM	$GAR_{PG\&E}$	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
2007	35	70	-2	57	0	0	12	26	35	41	45	48	51	52
2008	41	70	-2	60	0	0	19	32	40	45	48	51	53	55
2009	43	70	-2	60	0	0	21	33	41	46	49	52	54	55
2010	47	70	-2	61	0	0	22	34	41	46	49	52	54	56
2011	47	70	-2	61	0	0	23	34	42	46	50	52	54	56
2012	47	70	-2	61	0	0	23	35	42	47	50	53	54	56
2013	48	70	-2	61	0	1	24	36	43	47	50	53	55	56
2014	51	70	-2	62	0	7	28	39	45	49	52	54	56	57
2015	49	70	-2	62	0	4	26	37	44	48	51	53	55	57
2016	49	70	-2	62	0	4	26	37	44	48	51	54	55	57
2017	49	70	-2	62	0	5	27	38	44	48	52	54	56	57
2018	49	70	-2	62	0	6	27	38	44	49	52	54	56	57
2019	52	70	-2	63	0	12	31	41	47	51	53	55	57	58
2020	50	70	-2	63	0	8	29	39	45	49	52	55	56	58
2021	50	70	-2	63	0	8	29	39	45	49	52	55	56	58
2022	50	70	-2	63	0	9	29	40	46	50	53	55	56	58
2023	53	70	-2	64	0	13	32	42	47	51	54	56	57	59
2024	50	70	-2	63	0	9	30	40	46	50	53	55	57	58

TABLE 6
NORTHERN CALIFORNIA
CCA OWNED GENERATION COST BENCHMARKS ($/MWh)

MARKET PRICE $80/MWh, CCA OVERHEAD $5/MWh , CCA CRS = 0

					MAXIMUM COST OF CCA OWNED GENERATION TO MATCH $GAR_{PG\&E}$									
					CCA % OF LOAD FROM OWNED GENERATION									
	$CR_{PG\&E}$	MP	PM	$GAR_{PG\&E}$	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
2007	35	80	-7	61	0	0	0	20	32	40	46	50	53	56
2008	41	80	-7	63	0	0	8	26	37	44	49	53	56	58
2009	43	80	-7	64	0	0	9	27	38	45	50	54	56	59
2010	47	80	-7	64	0	0	9	27	38	45	50	54	56	59
2011	47	80	-7	64	0	0	10	28	38	45	50	54	57	59
2012	47	80	-7	64	0	0	11	28	39	46	50	54	57	59
2013	48	80	-7	65	0	0	12	29	39	46	51	55	57	60
2014	51	80	-7	66	0	0	16	32	42	48	53	56	59	61
2015	49	80	-7	65	0	0	14	30	40	47	52	55	58	60
2016	49	80	-7	65	0	0	14	31	41	47	52	55	58	60
2017	49	80	-7	65	0	0	15	31	41	47	52	56	58	60
2018	49	80	-7	66	0	0	16	32	41	48	52	56	59	61
2019	52	80	-7	67	0	0	19	35	44	50	54	57	60	62
2020	50	80	-7	66	0	0	17	33	42	49	53	56	59	61
2021	50	80	-7	66	0	0	17	33	42	49	53	56	59	61
2022	50	80	-7	66	0	0	18	33	43	49	53	57	59	61
2023	53	80	-7	67	0	0	21	36	45	51	55	58	60	62
2024	50	80	-7	66	0	0	18	34	43	49	54	57	59	61

TABLE 7
NORTHERN CALIFORNIA
CCA OWNED GENERATION COST BENCHMARKS ($/MWh)

MARKET PRICE $80/MWh, CCA OVERHEAD $10/MWh , CCA CRS = 0

					MAXIMUM COST OF CCA OWNED GENERATION TO MATCH $GAR_{PG\&E}$									
					CCA % OF LOAD FROM OWNED GENERATION									
	$CR_{PG\&E}$	MP	PM	$GAR_{PG\&E}$	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
2007	35	80	-7	61	0	0	0	7	22	31	38	44	48	51
2008	41	80	-7	63	0	0	0	13	27	36	42	47	50	53
2009	43	80	-7	64	0	0	0	15	28	36	43	47	51	54
2010	47	80	-7	64	0	0	0	15	28	36	43	47	51	54
2011	47	80	-7	64	0	0	0	15	28	37	43	48	51	54
2012	47	80	-7	64	0	0	0	16	29	37	43	48	51	54
2013	48	80	-7	65	0	0	0	17	29	38	44	48	52	55
2014	51	80	-7	66	0	0	0	20	32	40	46	50	53	56
2015	49	80	-7	65	0	0	0	18	30	39	45	49	52	55
2016	49	80	-7	65	0	0	0	18	31	39	45	49	53	55
2017	49	80	-7	65	0	0	0	19	31	39	45	49	53	55
2018	49	80	-7	66	0	0	0	19	31	39	45	50	53	56
2019	52	80	-7	67	0	0	3	22	34	41	47	51	54	57
2020	50	80	-7	66	0	0	1	20	32	40	46	50	54	56
2021	50	80	-7	66	0	0	1	20	32	40	46	50	54	56
2022	50	80	-7	66	0	0	1	21	33	41	46	50	54	56
2023	53	80	-7	67	0	0	4	23	35	42	48	52	55	57
2024	50	80	-7	66	0	0	2	21	33	41	46	51	54	56

Notes

BAY AREA COUNCIL

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