BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement) Portions of AB117 Concerning Community) Choice Aggregation)	Rulemaking 03-10-003 (October 2, 2003)

DRAFT SETTLEMENT AGREEMENT

Of City and County of San Francisco, County of Los Angeles and City of Chula Vista, CAL CLERA and Victorville, Local Government Comission Coalition, and Local Power

DRAFT - NOT FOR DISTRIBUTION

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The following document collates the positions of the City and County of San Francisco (CCSF), County of Los Angeles with Chula Vista (LACV), California Clean Resources Agency with the City of Victorville (CalCLERA-VV), The Inland Valley Development Agency (IVDA)[1], the Local Government Commission Coalition (LGCC) and Local Power, hereafter referred to as "CCA Cities," according to Edison's outline, as was requested by Judge Malcolm.

The document provides a base draft for resolution of inconsistent positions based on Initial Briefs, and has not yet been abridged or edited. While Reply Briefs are excluded from this draft in order to avoid duplication, parties are encouraged to add any sections from their Reply Briefs as they deem appropriate.

Parties are requested to;

1. use the Track Changes Utility in suggesting additions and deletions to this document, and;
2. Participate in a second CCA City conference call in order to establish a timely schedule for editing, refining and agreeing to a final settlement document.

Regards,

Paul Fenn
Local Power

[1]*IVDA is a regional joint powers authority consisting of the cities of Colton, Loma Linda, San Bernardino, and the county of San Bernardino. It was formed as a redevelopment agency pursuant to the California Community Redevelopment Law. In accordance with Health & Safety Code §33320.5, IVDA shall have and exclusively exercise powers of a redevelopment agency within the project areas in the territorial jurisdictions of its members.

I. Introduction

[LACV] On September 24, 2002, the Governor signed into law Assembly Bill 117 (AB117). AB117 authorized customers to aggregate their electrical loads as members of their local community (city, county or city and county) through a program called community choice aggregation. The bill authorized the community choice aggregator ("CCA") to "aggregate the electrical load of interested electricity consumers within its boundaries to reduce transaction costs to consumers, provide consumer protections, and leverage the negotiation of contracts,"[2] and required the CCA to submit an implementation plan with the Public Utilities Commission. The plan review and certification process was created to allow the Commission to determine a cost-recovery mechanism to be imposed on the CCA to prevent a shifting of costs to an electrical corporation's bundled customers. (AB117, Legislative Counsel's Digest.)

Approximately a year later, on October 2, 2003, the Commission issued an "Order Instituting Rulemaking to Implement Portions of AB117 Concerning Community Choice[3] Aggregation" – ("OIR") instituting this proceeding. The OIR proposed ways to implement relevant portions of AB117 and solicited comments from jurisdictional utilities and other parties on those proposals. The Commission indicated that AB117 does not define any role for the Commission in creating a CCA or authorizing its activities. However, AB117 establishes three preconditions for the initiation of community choice aggregation that require Commission action:

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[2]PUC 366.2c1

[3]AB117 (Ch. 838, 2002) added Public Utilities Code Sections 218.3, 331.1, 366.2, 381.1 and 394.25..3

(a) The Commission must adopt a "cost recovery mechanism" so that the investor owned utility is able to recoup certain costs associated with state power purchase contracts (Section 366.2(h) and (i)(1));

(b) the Commission must submit a report to the state legislature "certifying compliance" with provisions relating to the cost recovery mechanism (Section 366.2(i)(2)); and

(c) the Commission must adopt "rules for implementing community choice aggregation." (Section 366.2(I)(3).)

In the OIR, the Commission indicated that the topics it would address included the cost recovery mechanism. For other costs (such as start-up, implementation and transaction costs), the Commission relied upon its implementation of the direct access ("DA") program pursuant to AB1890. In this regard, the Commission stated:

> "For these purposes, a CCA's relationship with the local distribution utility appears comparable to that relationship between the utility and a "electric service provider" (ESP) in that the utility is providing an identical service to entities that are offering retail energy services to local customers. Therefore, we propose to apply the direct access service rules and service agreements to CCAs. Those rules require, among other things, the execution of a service agreement that describes the responsibilities of each party, and utility charges for delivery services.
>
> PG&E's Rule 22, SCE's Rule 22, and SDG&E's Rule 25 describe delivery services to ESPs and we propose that these tariffs be modified to incorporate AB117 requirements for CCAs. As modified, the tariffs would describe the respective responsibility of customers, CCAs and utilities in cases where utility customer in a CCA's territory decides to remain with the utilities." **[LACV CITATION?]**

A prehearing conference was held on October 29, 2003, followed by an Administrative Law Judge ruling bifurcating the proceeding into two phases such that the Commission would first consider (1) issues relating to certain utility costs that would be assumed or paid by CCAs, and (2) later consider issues more concerned with implementation rules and transactions between.CCAs, utilities and energy customers. On December 4, 2003, Presiding Administrative Law Judge Malcolm issued an "Assigned Commissioner's Ruling and Scoping Memo." The Ruling and Scoping Memo described the issues to be considered and a timetable for their resolution. Following the bifurcation of the proceeding, approximately five workshops were held under the direction of the Energy Division. Two workshops addressed the information that would be provided by the utilities to cities and counties interested in exploring the possibility of becoming community choice aggregators. The workshop was guided by the requirements of Section 366.2(c)(9) that:

> "All electric corporations shall cooperate fully with any community choice aggregators that investigate, pursue or implement community choice aggregation programs. Cooperation shall include providing the entities with appropriate billing and electrical load data, including, but not limited to, data detailing electricity needs and patterns of usage, as determined by the Commission, and in accordance with procedures established by the Commissions."

Two workshops were held concerning a general "strawman" proposal of the utilities concerning the potential charges to be assessed on community choice aggregators as part of implementation of any plan. Finally, a workshop was held to discuss the appropriate calculation of a cost responsibility surcharge ("CRS") for community choice aggregation ("CCA CRS") with the active involvement of the Department of Water Resources ("DWR").

Initial and reply testimony was submitted and hearings were held from June 2, 2004 to June 10, 2004 and again on June 24, 2004.

The agreed-upon general briefing format for issues in Phase I of this proceeding has been to use four categories: information issues, cost issues, specific fees for information, and service fees. Rate design, procedural proposals, and Commission authority issues were raised in the testimony and provide additional categories that are interwoven throughout. Following the filing of initial and reply testimony, the Inland Valley Development Agency ("IVDA") filed an intervention and testimony concerning a potential exemption from CCA CRS for converted.military installations and this last issue has been added to the outline. The CCA Cities have structured our comments to the ordered format to the greatest extent possible.

[CalCLERA] The Commission decision in this case can implement the intent of the Legislature in enacting AB117, stimulate the development of electric generation to serve the State of California, reduce costs for all electricity consumers and assist the economic revitalization of California.

To achieve these objectives the Commission should:

1. establish a Cost Responsibility Surcharge (C RS) which protects bundled ratepayers without suppressing or delaying the development of Community Choice Aggregation.
2. prevent the creation of additional stranded costs by investor-owned utilities (IOU) .
3. recognize the cost savings and other benefits to bundled ratepayers and the State of California from Community Choice Aggregation and ensure that the CRS reflects these cost savings and other benefits.

[LGCC] The Commission must ensure that Community Aggregators and IOUs are working together to provide electric service to their respective customers in a manner and at a cost that allows CCA to succeed, and that the CRS is calculated and collected equitably.

In adopting a decision on these issues, the Commission must bear in mind the goal of Assembly Bill 117, Chapter 838, Statutes 2002 (AB 117) of providing a viable choice to retail electricity consumers through CCA. The imposition of overly burdensome and ultimately unnecessary restrictions on the provision of customer information to Community Aggregators and the imposition of inflated and anti-competitive cost responsibility on CCA customers will thwart the goals of AB 117. Not only have the IOUs declared themselves to be direct competitors of Community Aggregators in violation of AB117's requirement that they "cooperate fully" with CCAs,[4] but they have presented proposals in this case to be the sole providers of essential services to Community Aggregators. The Commission cannot allow the IOUs to wield their market power to force Community Aggregators out of the market before the market even opens.

The Commission, in its decision on Phase 1, should:

Allow phase-in of CCA;

Ensure that Community Aggregators have access to information that will allow them to accurately plan and forecast their CCA programs;

Ensure that CCA customers are not responsible for IOU procurement activities after appropriate notice has been provided by the Community Aggregator of its CCA plans;

Require the IOUs to use consistent assumptions in developing the fees they propose to charge CCAs for information and services;

Employ a simple, fair methodology for calculating the CRS and require segmenting of the CRS (or its components) in the bills of both CCA and bundled service customers.

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[4]PUC 366.2c9

[IVDA] Finally, the CCA Cities request consideration of one CRS proposal: "[A] limited cost responsibility surcharge exemption for load that is shown or deemed to have been excluded from load forecasts on which either the DWR or utility relied in making its power purchases."[5] If no cost was incurred by DWR or an electric utility for a particular class of customers, there should be no cost responsibility for that customer class.

[5] *See* Prepared Testimony of Thomas K. Clarke for IVDA, Exhibit 43, at 3.

II Achieving the Legislature's Intent in Enacting AB 117

A. Summary

[Cal-CLERA] In enacting AB117 the Legislature conferred certain rights on all electric customers in California and on California cities and counties. The Legislature determined and enacted into law that California cities, counties and joint powers agencies of cities or counties are empowered to serve as CCAs.[6] The Legislature also expressed its intent that "each retail end-use customer that has purchased power from an electrical corporation on or after February 1, 2001, should bear a fair share of the Department of Water Resources' electricity purchase costs, as well as electricity purchase contract obligations incurred as of the effective date of the act adding this section, that are recoverable from electrical corporation customers in commission-approved rates"[7] and that it was also "the intent of the Legislature to prevent any shifting of recoverable costs between customers."[8]

This proceeding should ensure that <u>both</u> the rights conferred <u>and</u> responsibilities imposed on customers and community choice aggregators by the Legislature are fully and fairly respected.. Unfortunately, this proceeding is at risk of being subverted, by arguments which would effectively destroy community choice aggregation by attempts to impose unreasonable cost burdens and conditions on customers and potential community choice aggregators, using the anti-cost shifting language of AB117 as camouflage.

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6 AB117, section 4, codified as Public Utilities Code section 331.1 ("§ 331.1").

7 § 366.2(d).

8 § 366.2(d).

There are several basic principles that should be kept in mind when considering proposals to burden customers and potential community choice aggregators. Moreover, AB117 was not intended to immunize IOU shareholders from bearing a fair share of the costs and risks of implementing community choice aggregation.[9]

A. Legislature intended CCA to benefit all bundled service customers. The legislature intended CCA to provide a permanent recourse for all bundled service customers facing potentially unsatisfactory bundled service terms. The utilities agree that the ratepayers' recourse to CCA will introduce pressure to reduce customer costs (PG&E Witness Sandra Burns Reply Testimony on CRS Calculations, p.2-6, lines 36-7) – a clear benefit to bundled service customers. On the same day (September 24, 2004) that Governor Davis signed AB57 (Wright) authorizing electric utility procurement, AB117 was also signed, providing that (1) ratepayers shall be entitled to aggregate their electricity loads (PUC Section 366(a)), and that Customers shall be entitled to aggregate their electric loads as members of their local community with CCA (PUC Section 366.2. (a) (1)) – and customers may aggregate their loads through a public process with CCA, if each customer is given an opportunity to opt out of their community's aggregation program (PUC Section 366.2(a)(2)). Thus, the right of customers to form CCA through their local community thus confers a new, permanent entitlement on all bundled service customers that is statutorily defined alongside the right of customers to aggregate and negotiate with EPS on an opt-in basis (PUC Section 366(a)).

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9 Tr. 1037 (Fenn).

B. Legislature intended CCA to be a purchasing entity, not a Load Serving Entity. AB117 intended for Community Choice Aggregations (CCA) to be purchasing organizations facilitated through a "public process" (PUC Section 366.2(a)(2)) rather than Market Participants, and that notwithstanding Section 366, a CCA is hereby authorized to aggregate the electrical load of interested electricity consumers within its boundaries "to reduce transaction costs to consumers, provide consumer protections, and leverage the negotiation of contracts."(PUC Section 366.2(c)1). CCA are composed of ratepayers similar to opt-in aggregations, not Load Serving Entities or Market Participants, thus AB117 requires utilities to "fully cooperate" with CCA – whereas the utilities agree no such requirement exists under any law for utilities to cooperate with Electric Service Providers (EPS) or Independent Power Producers (IMPS) that will compete to serve CCA customers (PUC Section 366.2©)9).

C. The Utilities' definition of CCA as competitors contravenes legislative intent. Yet all three utilities' witnesses have indicated that they consider CCA to be competitors (PG&E Witness Sandra Burns, June 7, 2004 Evidentiary Hearing, p.454 line 22 to p.455 line 27; S.G.&E Witness Jim Magill, June 8, 2004 Evidentiary Hearing, p.542, lines 6-9)) and S.G.&E's witness indicated "seeing CCA as a utility". The Commission should take note of a dangerous conflict of interest presented by this categorization of CCA as "Market Participants" and "Load Serving Entities" for utility officers who have a fiduciary responsibility to their shareholders to prevent competitors from reducing bundled utility sales . The utilities admit that CCA will result in a decline in bundled sales, with less procurement of power (PG&E Witness Sandra Burns, June 4, 2004 Evidentiary Hearing).

D. Incentive ratemaking with utility procurement and URG contravenes legislative intent. Indeed, the advent of incentive ratemaking in the electric procurement proceeding ®.01-10-024, D. 04-01-050, p. 4) introduces a new conflict of interest for the utilities. Under incentive ratemaking, utilities agree that "to the extent that there was an incentive mechanism that encouraged (utilities) to retain load, bundled load, that might create an incentive for us to want to retain the bundled load and not be indifferent to customer departure." (PG&E Witness Sandra Burns, June 7, 2004 Evidentiary Hearing p.458 line 5 to p.459 line 18) Given the fiduciary responsibility of the utilities executives to 'their shareholders, it is clearly incumbent on the Commission to take note of and remove an avoidable conflict of interest for the utilities, which should not be forced into breaking the law. As the Legislature expressly requires utilities to "fully cooperate" with CCA – and PG&E's witness admits no law requires utilities to cooperate with Independent Power Producers (IMPS), EPS or any other Load Serving Entities participating in the market (PG&E Witness Del Evans, June 4, 2004 Evidentiary Hearing, p.319, Line 24 to p.320, line 2), the Commission must take note of an obvious legal contradiction and grant CCA full but hermetic access to all utility data, and dispense with the categorization of CCA as the utilities' "competitors."

E. Legislature did not intend CCA to be a form of municipalization. There are statutory restrictions on CCA participation in the market that reflect CCA's definition as groups of ratepayers in a local public process. CCA are forbidden by AB117 from aggregating electrical load if that load is served by a local publicly owned electric utility (as defined in subdivision (d) of Section 9604), thus firewalling CCA against municipalization. AB117 authorizes a CCA's grouping of retail electricity customers for a specific purpose: "to solicit bids, broker, and contract for electricity and energy services for those customers (PUC Section 366.2©)1). - not to become an Electric Service Provider, Load Serving Entity or Market Participant. The CCA's agreements for services are limited "to facilitating the sale and purchase of electricity and other related services,"(PUC Section 366.2©)1) - not to undertake an intrepid wires takeover. Even the utilities agreed CCA are not municipal utilities

F. Legislature intended CCA to have full access to all utility data. Accordingly, AB117 requires utilities' statutorily required "cooperation" to include making available all billing and load data (PUC Section 366.2(c)9.) to a CCA once it becomes a CCA through passage of a local ordinance (PUC Section 366.2(c)10.). Unlike Electric Service Providers (EPS), which as the utilities' real competitors existing Direct Access rules forbid access to confidential customer information, CCA are not subject to confidential 15/15 Rule data restrictions from existing Direct Access rules except in being prohibited from releasing this data to an ESP prior to the completion of its ratepayer opt-out period.

G. Legislature intended CCA to have customer-specific data upon formation to make the CCA opt out notification possible. A failure to make this data fully accessible to CCA would have several unlawful consequences. First, the utilities agree that if the 15/15 rule is applied, the CCA could not even perform the first two official opt-out notifications in violation of AB117's provision allowing CCA to make the notifications directly (PUC Section 366.2(c)13(B)) because the 15/15 rule precludes the utility from providing the level of detail that is required for a customer to make a specific decision around opting out (PG&E Witness Dell Evans, June 4, 2004 Evidentiary Hearing, p.328, lines19-27.

H. Legislature intended CCA to have equal access to all data if when utilities compete against CCA to administer Public Goods Charge funds. Second, If utilities were allowed to restrict data to CCA they consider competitors or municipal utilities when they are bidding against them for Public Goods Charge funds as provided in AB117 (PUC Section 381.1(a)), this would provide utilities with an unfair competitive advantage over CCA in designing their proposed programs, thus directly violating the requirement that the statutory requirement that utilities "fully cooperate...shall include data necessary to establish the data detailing electricity needs and patterns of usage, as determined by the commission, and in accordance with procedures established by the commission. Restricting CCA access to billing and load data useful for designing energy efficiency programs (such as customer-specific data) would also violate the CCA's right to co-design energy efficiency programs even in the even that they are administered by utilities (PUC Section 381.1(c))).

I. Legislature intended that only customer-attributable transaction costs be charged to CCA customers. The Legislature intended that all transaction and utility procurement-related costs imposed by any particular Community Choice Aggregator or CCA ratepayer to be born by the CCA and the CCA ratepayer. However, the legislature intended that all costs relative to implementing Community Choice Aggregation that *are not attributable* to any particular CCA or CCA ratepayer shall be born by bundled service customers (PUC Section 366.2(c)17) as the appropriate and necessary cost of having Community Choice as a permanent recourse to all California's bundled service customers to which AB117 "entitles" them (PUC Section 366.2. (a) (1)).

J. Legislature intended that the CRS be similarly limited to customer-attributable costs. Costs associated with scheduling utility procurement to maintain a 5-10% annual window of CCA load departure according to a CCA implementation plan process are the cost of having Community Choice as a choice in California. Accordingly, the added incremental cost of increasing short term procurement authorizations for a commensurate margin of power purchase agreements should not be included in the CCA CRS.

K. Legislature intended an Integrated Resource Calendar to avoid stranded costs and assets. The Legislature intended that any Cost Responsibility Surcharges imposed on CCA or CCA ratepayers be limited, and that utilities not be allowed to block CCA through overprocurement. The governor's recent letter to President Peevey also directs the Commission to avoid the creation of future stranded costs (Exhibit 47, p.1).

L. Legislature did not intend to shield shareholders against bearing a fair share of transaction and procurement-related costs. While bundled service customers are limited to paying for CCA transaction and procurement costs not attributable to any particular CCA customer, the legislature did not intend that utility shareholders should be protected against costs relative to CCA. The word "shareholder" does not appear in AB117. Thus, AB117 does not protect utility shareholders from cost shifting where necessary to accommodate CCA as a permanent recourse to California ratepayers.

M. Legislature intended a CCA-specific load profile-based CRS. The legislature intended CCA to administer energy efficiency and conservation programs, and requires CCA to implement the Renewables Portfolio Standard (RPS) law, SB1078 (2001, Sher). In fact, the current crop of cities implementing Community Choice has at minimum a 40% RPS goal – over three times the increase in renewables and conservation required by law of the utilities. Thus

N. Legislature intended CPUC to disclose a finite CRS to CCA customers – not a true-up. The Commission is required by AB117, after certification of receipt of a CCA's implementation plan and any additional information requested, the *commission shall then provide the community choice aggregator with its findings regarding any cost recovery that must be paid by customers of the CCA* to prevent a shifting of costs – a fee, based on Commission forecasting, which will not change for any CCA from year to year.

O. The Legislature intended that the "costs" as used in AB117 may be set on a forecasted basis.

III Achieving Consistency with the Governor's Energy Plans as reflected in PG&E's Exhibit 47

[Cal-CLERA] By letter dated April 28, 2004 to President Peevey (Exhibit 47), Governor Schwarzenegger articulated a number of energy objectives highly important to this proceeding:

> "California cannot afford to delay the construction of new power plants."[10]

The Governor also observed that "one of the greatest barriers to doing business in California is high energy costs."[11]

[Local Power] At the June 24 2004 Evidentiary, PG&E submitted a letter from Governor Schwarzenegger to CPUC President Michael Peevey, and in cross examination asked Local Power witness Paul Fenn to read isolated sentences from this letter onto the record - in particular, the sentences, "Now is the time for utilities to lock in these low prices through long-term contracts," to which Mr. Fenn disagreed on grounds that doing so would be illegal prior to completion of the Commission's already expedited R.01-10-024 and R.03-10-003.

Contradictory elements in the Governor's plans should not be taken out of context of the letter in which they appear, and should be reconciled to capture their true meaning.

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10 Exhibit 47, p. 2.

11 Exhibit 47, p. 3.

The Governor's letter also calls for "an electric market structure that encourages healthy wholesale and retail competition," and calls for a CPUC procurement process which "avoid[s] the creation of future stranded costs. (Exhibit 47, p.1)

In another passage of the Governor's letter that PG&E's Counsel also asked me to read, "(t)o compensate for these plant retirements and to plan for the inevitable return of strong economic growth, California cannot afford to delay the construction of new power plants. (Local Power Witness Paul Fenn, June 24, 2004 Evidentiary Hearing, pp. 1043, line 23 to p. 1044 line 20.) I said the CCA Cities did not understand the meaning of this sentence because current delays are market based – no bank is willing to underwrite power plants without long-term contracts.

CCA provides a superior method of overcoming this delay factor than utility procurement can offer, because like utility procurement, CCA involves the same kinds of long-term contracts to which the Governor referred – through a competitive market that does not run the risk of creating future stranded costs, which utility procurement and particularly URG directly entail through the rate-basing of contracts pursuant to AB57 and SB1976.

In fact, the outcome outlined in the Governor's letter is best provided by Community Choice and could be directly contravened by utility procurement. Thus, achieving consistency with the Governor's energy plans – to have a competitive market but also provide for long-term contracting and new capacity financing - hangs on expediting R.03-10-003 more than R.01-10-024.

[Cal-CLERA] In short, this proceeding presents an opportunity to achieve the objectives expressed in Exhibit 47. As explained in further detail below, establishing appropriate rules for Community Choice Aggregation (particularly recognition of the savings and benefits resulting from development of new generation by community choice aggregators), will stimulate the development of new generation, increase competition in wholesale and retail markets, reduce costs to all electric customers in California and support economic development.

IV. INFORMATION ISSUES

[LACV] As a preliminary statement, the County and City must note that the information that is required to be provided by the utilities to potential CCAs is guided by a statutory provision of AB 117. In particular, Section 366.2(c)(9) states:

> All electric corporations shall cooperate fully with any community choice aggregators that investigate, pursue, or implement community choice aggregation programs. Cooperation shall include providing the entities with appropriate billing and electrical load data, including, but not limited to, data detailing electricity needs and patterns of usage, as determined by the Commission, and in accordance with procedures established by the Commission. (Emphasis supplied.)

A. Service of All Load Within CCA Jurisdiction

[Local Power] AB117 requires a CCA's implementation plan to include universal access within its jurisdiction (PUC Section 366.2(c)4(A)) and requires a CCA to offer service to all residential customers in its jurisdiction (PUC Section 366.2(b)).

[LACV] This issue is directly related, as so many issues in this proceeding are, to statutory interpretation and direction. Section 366.2(b) provides that if a public agency seeks to serve as a community choice aggregator, it shall offer the opportunity to purchase electricity to all residential customers within its jurisdiction. Section 366.2(a) provides that customers shall be entitled to aggregate their electrical load as members of their local community with community choice aggregation if each customer is given an opportunity to opt out of their community's aggregation program.

Therefore, it is clear from the statutory direction that community choice aggregation is an action by customers in a jurisdictional area through their elected officials to provide electricity to themselves as residential customers and potentially all other load, subject to an opt out process. The statute does not provide any specific direction that says that 100% of all load must be served within the CCA's jurisdiction. The statute provides only that service must be offered to residential customers. Further, there is no direction as to the manner in which, or the timing for, services offered to classes of customers within the CCA's jurisdiction. The County and City.believe that how load within a CCA's boundaries may be served is a matter of the implementation plan and the Commission's oversight of the implementation plan once a CCA has made the determination to provide service.

[CCSF] CCSF agrees that all load within a CCA jurisdiction should be afforded the opportunity to aggregate. Insofar as any phased approach provides for universal access within defined sections of the community and provides an explicit and reasonable timetable to achieve complete community-wide aggregation, a phased approach is consistent with the law as long as the goal is to provide service to all load within a CCA jurisdiction.[12]

B. Phase-In of Community Aggregation Programs

[Local Power] AB117 requires a CCA's implementation plan to include universal access within its jurisdiction (PUC Section 366.2(c)4(A)), and requires a CCA to offer service to all residential customers in its jurisdiction(PUC Section 366.2(b)). The Commission should clarify that phasing is allowable on condition that it conforms to the universal access requirements of AB117, that all residential customers are offered service.

[LACV] It is in the Commission's discretion to review the method by which a particular community choice aggregator proposes to implement its plan of service. Mr. Monson, on behalf of the Local Government Commission Coalition (LGCC) provides detailed support for the use of phasing to eliminate confusion, reduce costs and otherwise allow a transition to community

[12] Exhibit 32 at 8.

choice in a manner which will be least disruptive to consumers and current utility operations. [Ex. 28 at 21-23, Ex. 29 at 11-12.]. Thus, under such circumstances and within limits, phasing should be allowed.

The utilities are split in their position with regard to phasing. Pacific Gas & Electric Company ("PG&E") believes that phasing may be appropriate if accomplished within a limited period of time. [Ex. 14 at 1-1 to 1-2.] In particular, Mr. Evans testified that a limited form of phasing may be essential if switching of customers to community choice aggregation is based on billing or meter read dates which vary over the month. [Tr. 298-299.] Thus, plan implementation within PG&E's territory may take at least two to three months at a minimum in any event. Dr. Jazayeri on behalf of Southern California Edison Company ("SCE") indicated that a specific geographic area could be a first phase of implementation if service was provided to all classes of customers within that geographic area. [Tr. 173.]

Only SDG&E categorically rejects the concept of phasing. [Ex. 15 at 12.] SDG&E's argument is that a CCA would "cherry-pick" customers of the investor owned utility and leave the investor-owned utility with the least attractive customers remaining on utility service. *[Id.]* However, it is clear from SDG&E's other testimony that they propose to utilize customer.specific information to provide notices of their own to pick out attractive customers in a manner that would, presumably, encourage select customers to opt out of CCA service for

SDG&E service, thus making CCA service less attractive – and more difficult -- to develop. [Ex. 23 at 12.] In fact, nearly all of SDG&E's positions in this proceeding seem expressly designed to prevent the economic and timely development of community choice aggregation. SDG&E testified in support of immediate, total implementation [Tr. 633] but the County and City argued in the workshop that a massive transfer was difficult and expensive.

The CCA Cities believe, consistent with Mr. Monson's testimony, that phasing should be an option available to CCAs. *[See als*o, Fulmer, Ex. 32.] Such phasing could be by geographic area as discussed in Dr. Jazayeri's cross-examination, or by a single large customer, such as a governmental entity, that serves all classes that receive utility service and has accounts in all classes of service in a form of "pilot" program as an initial phase.

Thus, the CCA Cities specifically request the Commission provide that CCAs have the option to propose phasing as part of their implementation plans to be reviewed by the Commission.

[CCSF] CCAs should be entitled to phase-in their Community Choice Aggregation Program over some reasonable period of time. No party has identified a conflict between the legislative requirement for universal access and equitable treatment of all classes of customers and a phased approach to aggregation. Nor is there is anything in AB117 that prohibits CCAs from a phase-in of their CCA Programs. AB 117 only requires that CCAs provide universal access to all customers within the CCA boundaries and does not set a particular time limit or other constraints on the logistical issues of formation.

Such phasing may allow a jurisdiction the option of terminating its program if unexpectedly significant or insurmountable problems arise in fulfilling its obligations. From a practical perspective, a phased approach, particularly for larger communities, may also provide the utilities with more time to both process thousands of account change transactions in the most efficient manner and alter their own short-term procurement contracting plans.

At a policy level, Dr. Jazayeri for SCE stated that phase-in should not be allowed because it "introduces a lot of difficulty in the process."[13] However, he also acknowledges that a CCA may set up a plan that serves one group of customers first and then phases in other groups over time as long as universal service is achieved.[14] Although he had reservations that this might introduce problems where a potential CCA decides to discontinue the process midstream, he also acknowledges that sufficient Commission rules could be established to achieve universal service.[15] Such rules could be used to anticipate any potential problems with a phase-in approach, especially if there are advantages to a phase-in approach. It appears that SCE would not be opposed to a phase-in approach as long as there were adequate safeguards to allow the Commission to have adequate control over the phase-in approach.[16]

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13 Reporter's Transcript (RT) at 138.
14 RT at 135.
15 RT at 136.
16 RT at 141.

PG&E supports a phase-in approach over some short time period because it would ease the administrative burden of switching over thousands of accounts at one time.[17] Phase-in over several months could be necessary just to identify problems in the CCA transaction process. In fact, it may be at least 60 days before billing problems for a typical residential customer have come to PG&E's attention, due to the lag time between billing cycles and payments. This does not even count the amount of additional time it will take to rectify the problem between the CCA and utility.[18]

[LGCC] As recognized by PG&E and other parties, LGCC's proposal to phase in CCA programs is a reasonable accommodation of the IOUs' concerns regarding the difficulty and expense of implementing CCA on a wide scale.[19] Phase-in of CCA is a reasonable method for "testing" the IOUs' systems for implementing CCA and the Commission's rules for CCAs. Phase-in also benefits new CCAs and their customers by allowing CCAs to gain experience before being required to provide service on a broad basis.[20] In short, phase-in is a reasonable method for avoiding the mass confusion that could result if any of the procedures, systems, or rules for CCA prove to be problematic.

SCE and SDG&E are the only parties that flatly oppose the phase-in proposal. Instead of addressing the issue on the merits, SCE argues that phase-in could violate AB 117's requirement of universal service, equitable treatment of customers, and customer "opt-out", stating that it is the "Commission's task to interpret the totality of [AB 117] and determine if phase-in of a CCA

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[17] RT at 299.
[18] RT at 314.
[19] Exh. 13, at 4-4.
[20] Exh. 28, at 21-23.

plan is consistent with the law."[21] Contrary to SCE's claim, there is no legal barrier to adoption of a phase-in program.

Public Utilities Code section 366.2(b) provides, "If a public agency seeks to serve as a community choice aggregator, it shall offer the opportunity to purchase electricity to all residential customers within its jurisdiction." Section 366.2(c)(2) establishes the Community Aggregator as the retail electricity provider in its jurisdiction unless a customer chooses to opt out of the CCA program. Section 366.2(c)(4) requires that CCA programs offer universal access, reliability, and equitable treatment of all customers.

It is a well-settled legal principle that administrative agencies, such as the Commission, have wide latitude in implementing statutes that the agency is charged with interpreting and enforcing.[22] The Commission was directed by AB 117 to implement CCA; thus, the Commission's interpretation of the statute cannot "be disturbed unless it fails to bear a reasonable relation to statutory purpose. . . ."[23] A phase-in program that results in universal service is a reasonable approach that is consistent with the purpose of AB 117 to give customers a choice in electricity providers and the Commission's mandate to protect consumers.

In order to prohibit phase-in of CCA the Commission must determine that such an approach is prima facie illegal under AB 117, regardless of the nature and design of the phase-in program. The Commission cannot make such a determination. Community Aggregators should have the opportunity to propose phasing concepts in their implementation plans for Commission review for consistency with the requirements of AB 117.[24]

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[21] Exh. 7, at 5; Exh. 8, at 23; Exh. 9, at 10.
[22] *Coca-Cola v. State Board of Equalization*, (1945) 25 Cal.2d 918, 921.
[23] *Greyhound Lines v. Public Util. Comm.,* (1968) 68 Cal.2d 406, 410-411.
[24] Both PG&E and SCE stated that a case-by-case review of phase-in programs is a reasonable approach should the Commission determine that phase-in is legal and appropriate. (Exh. 13, at 4-4; TR 233:18-26.)

C. CCA-Specific Load Profiles

[LACV] The issue of whether the utilities should be required to prepare CCA-specific load profiles has been a hotly debated issue. The utilities' position is that such load profiles may be ineffective as well as too burdensome and costly to prepare. The County and City, in this regard, support the position of the City and County of San Francisco that should a CCA wish to have a specific load profile prepared for them, that such an option should be available to them. [Ex. 31 at 13-14.]

In the course of cross-examination, a middle ground was described. Both Ms. Keilani for SDG&E [Tr. 85-86.] and Mr. Garwacki for SCE [Tr. 261-262] discussed a "quick and dirty" method. As described by Mr. Garwacki, the utility would use system profiles and then perform a.usage adjustment by the system average load profile and thus construct a CCA-specific loaded average profile. This method would also use a type of weather zone methodology to match the weather zone profile of the CCA to the system profile and then rebuild up a CCA profile. Ms. Keilani indicated that the time necessary to prepare an evaluation by SDG&E under this methodology for the City of Chula Vista would be "moderate or easy" to prepare. Under the definition submitted in the information workshop, this means that less than eight man hours would be necessary to provide this information. Mr. Garwacki indicated that it would take longer than that to provide the information by SCE for the County but that it would be less than 40 hours.

Thus, the County and City believe that, at a minimum, an evaluation of the system average load profile versus a preliminary analysis of the load profile of the CCA, as described above, should be provided by the utilities. Further, as this material would be relatively “easy” to provide, it should be provided at no cost since it is essential for the CCA to understand and accurately procure and schedule power and evaluate whether aggregation is a viable option.

Indeed, the County and City believe that all information costs as described in this section are issues associated with implementation. As describe more fully herein, the County and City believe such implementation costs should be accrued within Account 376 and paid by all ratepayers consistent with Section 366.2(c)(17).

[CCSF] The costs and benefits of using CCA specific load profiles for a variety of purposes (i.e. calculating CRS, calculating reserve margin adequacy, scheduling power, and settling power transactions with the ISO), should be explored more fully in Phase 2 of the proceeding. There are potential benefits to developing the database necessary to calculate the load shape of a potential or existing CCA. Clearly the first, and possibly the most important benefit, is to provide the basis for the CCA or its suppliers to schedule generation resources to serve the CCA’s customers through the California Independent System Operator (CAISO) as accurately as possible.[25]

[25] Exhibit 26 at 13.

If system average class load shapes are used to develop the schedule for an individual CCA, the results will be a significantly greater likelihood of over scheduling or under scheduling of power in each hour. For parties like CCSF, a system average load shape for a city with its customer mix and its climate would likely result in overscheduling during the summer on-peak period, and under scheduling during the summer off-peak period. There would therefore be unnecessary financial consequences for CCSF that would flow through the CAISO settlement process. In addition, if cities with load pockets like San Diego and San Francisco overscheduled on-peak due to the use of average load profiles, one consequence could be unnecessary congestion costs.[26]

D. Boundary AND OTHER Metering

AB117 requires provides that, at the request and expense of any community choice aggregator, utilities shall install, maintain and calibrate metering devices at mutually agreeable locations "within or adjacent to" the CCA's political boundaries – not merely "Boundary Metering." Furthermore, AB117 provides that the electrical corporation shall read the metering devices and *"provide the data collected to the community aggregator"* at the aggregator's expense. To (PUC Section 366.2(c)18).

26 Exhibit 25 at 11.

The ability to install metering devices of any kind – at mutually agreeable locations on the utility's grid – has implications that are illustrated by San Francisco's adopted Community Choice ordinance, under which an Implementation Plan will be submitted to the San Francisco Board of Supervisors in November of this year (City and County of San Francisco Ordinance 86-04, May 27, 2001, p.4), which may amend and adopt the plan by ordinance and send it to the Commission at that time.

The "new" metering language in AB117 is important because it underscores the ability of a CCA and utility to measure the benefits from new capacity and load reduction technologies installed by the CCA's ESP.

The basic requirements of AB117 combine to provide guidance on how the legislature intended availability of data relative to a CRS definition. The legislative intent of AB117 is found in a combination of provisions:

(1) the legislative intent of AB117's energy efficiency funds language,
(2) the requirement that utilities provide data on customers' energy needs and patterns of usage,
(3) the requirement that utilities install metering devices *within or adjacent to* the community aggregator's political boundaries,
(4) the detail that implementation plans are the basis of the CRS mechanism determination after a 90 day "certification" process (PUC Section 366.2©)7), and
(5) that implementations must include details about who is the underwriter, particularly "the rights and responsibilities of parties"(PUC Section 366.2(c)3(E)).

Thus, the Commission, while lacking ratesetting jurisdiction over Community Choice Aggregations, has broad discretion, based on a CCA's implementation plan, to impose CRS penalties (this regulatory authority also lacking due to CPUC Decision 04-01-050, which forbade Commission review of electric utility procurement contracts pursuant to AB57.)

[LACV] No position. CCA pays.

[CCSF] The law requires IOUs to provide adequate and accurate meter information to allow a CCA to procure resources and manage its energy load. AB117 states that "[a]t the request and expense of any community choice aggregator, electrical corporations shall install, maintain and calibrate metering devices at mutually agreeable locations within or adjacent to the community aggregator's political boundaries."[27] It is the obligation of the CCA to pay reasonable incremental costs incurred by the utilities as the result of any additional metering.

E. Relevancy of Information to Community Choice Aggregation

Making Customer-specific billing and load data is critical to the ability of a CCA (1) to provide statutorily required customer notifications to all ratepayers in its jurisdiction, and (2) to design and measure the benefits of cost-effective energy efficiency and conservation programs.

Accordingly, AB117 requires utilities' statutorily required "cooperation" to include making available all billing and load data (PUC Section 366.2(c)9.) to a CCA once it becomes a CCA through passage of a local ordinance (PUC Section 366.2(c)10.).

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27 PUC §366.2(a)(18).

Customer-specific data is needed prior to the beginning of the opt-out period so that a CCA may perform the required opt-out notifications, in violation of AB117's provision for CCA to make the notifications directly to ratepayers (PUC Section 366.2(c)13(B)). The utilities agree that, if applied, the 15/15 rule would preclude the CCA from providing the first two notifications required by this section of code because the 15/15 Rule precludes utilities from providing the level of detail that is required for a customer to make a specific decision around opting out (PG&E Witness Dell Evans, June 4, 2004 Evidentiary Hearing, p.328, lines19-27).

AB117 provides that CCA have the opportunity to administer (PUC Section 381.1(a)) and the right to design (PUC Section 381.1(c)) energy efficiency programs even if other parties are the administrator. Accordingly, AB117 requires that utilities make customer billing and load data available to a CCA "*including, but not limited to, data detailing electricity needs and patterns of usage*, as determined by the Commission" (PUC Section 366.2(c)9) in addition to requiring utilities to install and report data from new meters to the CCA at is own expense.

The fact that the utilities maintain confidentiality of even their interval meter data while downplaying the statutory requirement that they install and report data from new meters in AB117 goes contravenes obvious legislative intent in AB117.

If CCA are denied access to their own customer-specific and interval meter data that utilities admit using in designing their energy efficiency programs (SDG&E Witness Wendy Keilani, June 2, 2004, p.109, line.2) in applications for such energy efficiency funds, CCA would suffer a competitive disadvantage bidding against utilities for Public Goods Charge funds as provided in AB117 (PUC Section 381.1(a)). Allowing utilities to exploit an unfair advantage in depriving customers the opportunity to administer their own programs would directly violate the statutory requirement that utilities "fully cooperate" with CCA, in addition to offering the data necessary to establish the data detailing electricity needs and patterns of usage, as determined by the commission, and in accordance with procedures established by the commission, as cooperation is statutorily defined. Restricting CCA access to billing and load data that is useful for designing energy efficiency programs (such as customer-specific load data) would also violate the CCA's right to co-design energy efficiency programs even in the even that they are administered by utilities (PUC Section 381.1(c)).

Moreover, without the data, CCA will be unable to prepare Implementation Plans as outlined in AB117.

[LACV] During the course of this proceeding, two workshops were held to discuss information that would be necessary for CCAs to adequately evaluate their options and make an informed decision. As discussed above, the utilities are required by statute to fully cooperate in this regard.

During the course of the workshops, numerous areas of information were identified. In part, such information was already required to be provided by the utility at the request of the

CCA by previous Commission order. Further areas of information were identified. As discussed in the cross-examination of Ms. Keilani, all categories of information within the "Appendix B – Information Item List" to the "Joint Utility Report on Community Choice Aggregation Information Issues – January 30, 2004" were identified by the utilities as either being free, easy or moderate to provide (which is defined as less than eight hours of effort) or are not available. [Tr. 94.]

However, it is equally clear, as exemplified by Exhibit No. 6, that San Diego Gas & Electric Company ("SDG&E"), in particular, refused to provide any of the information not otherwise required by previous Commission order, the so-called "free" information. Without specific direction from the Commission, the material that was identified by the CCA community as being necessary for them to evaluate their CCA opportunities must be ordered by this Commission. Further, as discussed above and below, the cost of providing such information is in each and every instance less than eight hours of effort. [Tr. 94.] The information requested by CCAs is less than the normal data requests submitted to the utilities in any of their pending matters. As such, utility opposition to providing this information should be ignored and the utilities should be required to provide the information on request.

Further, as the cost of providing such information is minimal, the utility should be required to provide this information as an implementation service. As this information is.required to be provided by statute, there should also be no charge. Indeed, the information may be provided to those who wish to become CCAs but who determine, based on that information, not to proceed with implementation.

[LGCC] AB 117 states:

All electrical corporations shall cooperate fully with any community choice aggregators that investigate, pursue, or implement community choice aggregation programs. Cooperation shall include providing the entities with appropriate billing and electricity load data, including, but not limited to, data detailing electricity needs and patterns of usage, as determined by the commission, and in accordance with procedures established by the commission.

Customer load information is an essential input to key elements of a CCA program, affecting the cost of service, rate design, planning for resource adequacy, and other items. The strategy of the IOUs to date has shown little evidence of "cooperat[ing] fully" with Community Aggregators, but instead has been to argue that prior Commission decisions on direct access prevent the IOUs from releasing such information except in aggregated format.

In Decision 03-07-034 the Commission required the utilities to provide customer data to Community Aggregators as specified in Appendix C within one week of a request. The Commission also indicated that Appendix C is the minimum level of information that should be released: "We will consider ordering the utility to provide additional types of information in the broader inquiry into AB 117 aggregation issues." The information in Appendix C is the absolute minimum necessary for any prospective CCA.

F. Confidential Customer Information

[Local Power] Direct Access confidentiality rules (Rule 15/15 and the 500 Kilowatt Rule) do not apply to CCA, but should continue to apply EPS and other Market Participants for the simple reason that whereas CCA are formed by ratepayers through a public and non-profit process, EPS are indeed market participants and Load Serving Entities formed by private, for-profit energy suppliers. It should be noted that as private, for-profit suppliers, utilities should not be entrusted with confidential customer information either. Thus AB117 establishes a degree of regulation over EPS (PUC Section 394.25. (a) through (d)). For similar reasons, AB117 establishes regulation of utility services, providing that “the commission shall determine the terms and conditions under which the electrical corporation provides services to community choice Aggregations and retail customers.” (PUC Section 366.2©)9. In stark contrast, AB117 gives CCA relatively autonomous ratesetting authority for its ratepayers (PUC Section 366.2(c)3(B)). Thus, while EPS and indeed utilities should not be entrusted with unrestricted use of confidential customer data, CCA should and must be entrusted with this responsibility over their own data for the reasons listed above.

Thus, customer-specific data and the utilities load research data, both of which the utilities maintain as confidential (Edison Witness Akbar Jazayeri, June 3, 2004 Evidentiary Hearing, p.188, lines 8-23), may be made accessible to CCA, though not EPS. Edison's witness agrees that data from new meters installed within or adjacent to the CCA jurisdiction pursuant to PUC Section 366.2©)18 is not confidential. (Jazayeri, June 3, 2004 Evidentiary Hearing, p.190, lines 8-15). The same witness indicated Edison's unwillingness to release confidential information to a CCA "prior to a CCA being formed." (Jazayeri, June 3, 2004, p.193, lines 11-14).

Mr. Jazayeri neglects to note that a CCA is formed when the local governing board of a municipality, county or joint powers agency elects to combine the loads of its residents, businesses, and municipal facilities in a community wide electricity buyers' program. Under AB117, such a governing board that elects to implement a CCA program within its jurisdiction "shall do so by ordinance" (PUC Section 366.2(c)10(A)).

Once a CCA is formed, it needs customer specific and interval meter data in order to facilitate the transaction and prepare an Implementation Plan for submission to the Commission – a plan whose specific details will determine the Commission's calculation of a CRS.

Thus AB117 requires to "cooperate fully" with any CCA that "*investigate, pursue, or implement CCA*," and cooperation is defined as including providing the entities with appropriate billing and electrical load data, including, but not limited to, *data detailing electricity needs and patterns of usage,* as determined by the commission, and in accordance with procedures established by the commission. (PUC Section 366.2©)9). It is important to observe that including data detailing electricity needs and patterns of usage is not required only with CCA that “implement” CCA but even CCA that merely investigate or pursue CCA.

It is dangerous to argue that utilities should protect the confidentiality of ratepayers against CCA as if they were competitors. . Yet all three utilities’ witnesses have indicated that they consider CCA to be competitors (PG&E Witness Sandra Burns, June 7, 2004 Evidentiary Hearing, p.454 line 22 to p.455 line 27; SDG&E Witness Jim Magill, June 8, 2004 Evidentiary Hearing, p.542, lines 6-9)) and SDG&E’s witness sees the CCA “in a similar fashion to a utility” (Magill, June 7, 2004 p.545, line 4), even though AB117 specifically firewalls CCA against municipal utilities by forbidding CCA from aggregating electrical load if that load is served by a local publicly owned electric utility (PUC Section 366.2©)1).

The CCA is not a competitor – even the same witness who said he sees CCA in a similar fashion to a utility admitted, upon my further questioning, “a CCA is not a municipal (utility).” (Magill, June 8, 2004, p.545, line 12). If a CCA is not a municipal utility and is statutorily required to be a local government, then it is by statutory definition not a “utility” at all.

The Commission should take note of a dangerous conflict of interest presented by this categorization of CCA as “Market Participants” and “Load Serving Entities” for utility officers who have a fiduciary responsibility to their shareholders to use any means necessary to block competitors. The utilities admit that CCA will result in a decline in bundled sales, with less procurement of power (PG&E Witness Sandra Burns, June 4, 2004 Evidentiary Hearing).

CCA are ratepayers exercising their right to depart from utility procurement. Even SDG&E's witness agreed that CCA customers are "members" of the CCA and not merely customers of it (SDG&E Witness James Magill, June 8, 2004 Evidentiary Hearing, p.544, lines 14-20), reflecting the statutory language entitling *ratepayers to aggregate through a public process called CCA*. Second, CCA are public and non-profit. Utilities, being both for profit and privately controlled, offer ratepayers no such assurance of public meeting laws and electoral accountability. CCA are therefore better stewards of confidentially protected customer data than utilities under their basic legal and constitutional characteristics.

While in order to facilitate transactions, the CCA needs customer-specific and all interval load data even at the implementation plan drafting stage, EPS should be restricted to anonymous data that protects ratepayer confidentiality until the 120 day opt out period is complete, as requested by the utilities. The EPS may receive the data at this point because of the fundamental difference between Direct Access (DA) and CCA – the opt out provision under which CCA ratepayers aggregate to leverage purchasing power and lower transaction costs. Under DA, the authorization to switch a customer to a supplier was conducted in much the same manner that under the DA confidentiality rule data was released - through a written authorization.

SDG&E's witness agreed that whereas under Direct Access customers were switched through a written authorization and thus utilities authorized release of the data to an ESP through a written authorization, under PUC Section 366.2(a)2 a CCA customer's legally binding participation in an ESP contract does not require a positive written declaration, but all customers shall be informed of the opportunity to opt out prior to transfer to an ESP's contract.

Thus the CCA's release of confidential data to an ESP or other third party would logically occur upon the terminus of the opt-out period – when the customer may no longer opt out of the contract without incurring a penalty. In response to being asked in Local Power's cross-examination whether SDG&E objects to releasing the protected information after the opt out period if the customer hasn't opted out, SDG&E's witness said he "would say we would not object if the notification included the safeguards as we proposed, which is that the notice provides clear and unequivocal -- clearly explains to customers that the Commission is requiring the utility to turn over their private information to a CCA provider even if they do not give their affirmative permission and it describes the specific information that is disclosed. Then I would say that we would not object." (SDG&E Witness Wendy Keilani, June 2, 2004 Evidentiary Hearing, p.117, line 14 to p.118, line 4). While Ms. Keilani's interpretation of CCA as competitors is mistaken for the reasons already given, the treatment she proposes for CCA would be appropriate for governing release of the confidential data to EPS or third party data services.

PG&E indicates that "customers are concerned about maintaining the confidentiality of their utility information."" (PG&E Opening Brief, p.62). PG&E cites witness Barkovitch in saying that "customers want to be able to make the decision as to whom the information should be released. They want to have control over that."" (CCSF/Barkovitch, Tr.747). However, this does not in any justify electric utility access to the confidential data, and more specifically whether customers trust a for-profit, unelected investor-owned utility with their information more than they would trust it with a non-profit, elected, ratepayer-formed local government.

PG&E proposes applying the same confidentiality rules that apply to ESPs to CCAs, proposing that customer name, service and billing address, account number, and usage data be withheld until written consent of the customer or after the first 60 days of the opt out period have passed. (Opening brief, p.62). Yet AB117 requires that (t)he community choice aggregator shall fully inform participating customers at least twice within two calendar months, or 60 days, *in advance of the date of commencing automatic enrollment*." (PUC 366.2c13). Thus, PG&E's position clearly violates the intent of the legislature that CCAs have this information prior to the transfer of customers. Thus the 15/15 and 500 kw rule do not apply to CCAs.

Furthermore, AB117 specifically requires utilities to provide this data not only to CCAs upon enrollment, but to CCAs that are merely investigating CCA:

> "All electrical corporations shall cooperate fully with any community choice aggregators that INVESTIGATE, PURSUE OR IMPLEMENT
>
> community choice aggregation programs. COOPERATION SHALL INCLUDE providing the entities with appropriate billing and electrical load data,
>
> including, but not limited to, data detailing electricity needs and patterns of usage, as determined by the commission, and in accordance with
>
> procedures established by the commission" (My emphasis, PUC 366.2c9).

Unlike electric utilities but like the Commission, CCAs are formed for the specific purpose of protecting consumers:

> "Notwithstanding Section 366, a community choice aggregator is hereby authorized to aggregate the electrical load of interested electricity consumers within its boundaries to reduce transaction costs to consumers, *provide consumer protections*, and leverage the negotiation of contracts" (PUC 366.2c1).

Thus, in addition the CCA implementation plan containing consumer protection measures as PG&E points out (PUC 366.2c3E and PG&E Opening Brief, p.64), AB117 includes consumer protection among the specific purposes of CCAs. Thus, unlike utilities, which exercise unrestricted access to confidential customer data, CCAs may be trusted with unrestricted access to the data under Commission rules and procedures. Under this construction, Local Power agrees with PG&E's suggestion that "as part of its review of the CCA's implementation plan and registration materials, the Commission should assure itself that the CCA has adequate procedures to protect customer confidentiality." (PG&E Opening Brief, p.64).

PG&E proposes that if the Commission agrees CCAs must have the confidential information prior to enrollment, that release of the data be tied to the CCA's implementation plan and in particular the consumer protection measures relative to confidential data (PG&E Opening Brief, p.65). However, as in the proposal to delay release of the data until enrollment, this approach would violate AB117's requirement that the data be provided by utilities to CCAs that

INVESTIGATE, PURSUE OR IMPLEMENT" CCA (PUC 366.2c9). Clearly the legislature intended CCA's that wish to ascertain whether to PURSUE or IMPLEMENT CCA would first INVESTIGATE the option, and would need the data ("including, but not limited to, data detailing electricity needs and patterns of usage") in order to identify specific opportunities that would justify PURSUING or IMPLEMENTING CCA. Thus, AB117 requires the utilities to make the data available to a CCA prior to completion of the Implementation Plan. Again, Local Power suggests that the Commission condition the release of confidential data to CCAs that have passed an ordinance such as San Francisco's (Ordinance No. 86-04, May 27, 2004) establishing a CCA.

The Commission has full discretionary authority to place restrictions on the use of released data, and in fact state agencies routinely trust local governments, which are themselves agencies of the state of California, with sensitive data. Local Power recommends that the Commission restrict CCAs from releasing confidential customer information to any party but an ESP, and delay this release authorization until after the enrollment of a CCA's customers after the 60 day opt out period, in order to assure adequate consumer protection. Thus, the CCA could investigate and pursue CCA prior to implementation, would be able to notify all aggregated customers of their impending enrollment and opt-out opportunity, without any breach of confidentiality taking place.

[LACV] This is possibly the most contentious issue in the case. As stated repeatedly in the testimony of various parties, a CCA is required under section 366.2(c)(13)(A) to provide a succession of notices to its member/customers. These notices are to "fully inform participating customers at least twice within two calendar months, or 60 days, in advance of the date of commencing automatic enrollment." Subsection 15 then provides that once the community choice aggregator's contract is signed, the community choice aggregator shall notify the applicable electric corporation that community choice service will commence within thirty days. [366.2(c)(15).] Under Subsection 16, once notified of the program, the electrical corporation "shall transfer all applicable accounts to the new supplier within a 30 day period from the date of the close of their normally scheduled monthly metering and billing process." [366.2(c)(16).]

It is the position of the utilities, however, that information related to customers who would otherwise be covered by the "15/15" and "500 kW" rules related to direct access ("DA") service should not be provided to the CCA until such time as service is provided by the CCA. SDG&E, however, carries this matter several steps further. SDG&E proposes **NEVER** to provide such information even after such customers become the customers of CCAs absent specific written consent. [Ex. 3, 4 and 5.] Further, SDG&E requests the authority to review and approve the notices that would be sent by the CCAs, and require the CCAs to use SDG&E for such notices. SDG&E also wishes to send out its own individual notice, without review by the CCA, and yet bill the CCA for SDG&E's own "notice." [Ex. 23 at 10, 12.]

The County and City believe that the position of the utilities, and especially SDG&E, is untenable in this regard. This issue fully demonstrates the inherent inconsistency within the.11 utilities' positions in this rulemaking. The utilities, depending on circumstances, either embrace DA rules or argue that such rules are inapplicable. In both instances, the positions seem designed to thwart CCA service. Here, the utilities (at least SCE and SDG&E) wish to prevent information from being provided and so argue the DA rule (designed for much different circumstances) is sacrosanct (discussed above). The position is similar with respect to "CCA CRS" (discussed below). However, as to the number of charges and level of such charges, the utilities argue the DA rules are either inapplicable or antiquated, and thus cannot be used. [Ex. 22 at 2.]

The County and City believe the DA rules and charges are appropriate proxies. The County and City further believe that providing customer-specific information to a CCA is consistent with DA rules.

The "15/15" rules that the utilities cite refer to DA service. The DA rules were established to provide customer identity protection and to avoid providing confidential load information to competing energy service providers ("ESPs"). The community choice aggregation program, as designed by AB 117, effectively turns this situation upside down. The community choice aggregator is defined as a city, county, or city and county whose governing board elects to combine load of its residences, businesses, municipal facilities in a community electricity buyers' program. Section 331.1(a). Section 366.2(a)(1) provides that "customers shall be entitled to aggregate their electric load as members of their local community with community choice aggregation. Customers may aggregate their load through a public process with community choice aggregators, and each customer is given an opportunity to opt out of their community's aggregation program." Section 366.2(a)(2).

Under these circumstances, the CCA is a consortium of customers who have the right to their own customer information consistent with the "15/15" rule if it is applied to CCA service. The decision to become a CCA is made by elected officials representing these individual.12 customers. Indeed, as admitted by several utility witnesses, the utilities will be competing with CCAs for customers within the CCA jurisdiction. *[Se*e, e.g., Tr. 455.] Thus, the retention of confidential information by the utilities and preclusion of such information by the utilities from the CCA will give the utilities a competitive advantage. This advantage is exactly what the Commission was concerned about when adopting the 15/15 rule for ESPs.

AB 117 is silent on this subject other than to indicate that information would be provided consistent with Commission policy. There is nothing inconsistent in Commission policy with providing customers their own information. There is, however, Commission precedent as reflected in the rules asserted by the utilities themselves that would deny the utilities as competitors, to capture customers within the CCA program by maintaining an exclusive lock on customer-specific information. CCA is an "opt-out" program, essentially turning bundled utility service into an "opt-in" option directly equivalent to DA service. DA service, especially the opt-in element, is the basis for the 15/15 rule. Thus, it should be used to exclude the utility, not the CCA, from such customer information.

Further, the information that has been denied falls into two categories: (1) basic contact information and (2) load information. As to basic contact information, it is clear that CCA has an obligation to notify its member/customers and cannot do so without information as to customer name, address and possibly, contact person. As was discussed in testimony, the CCAs do not have any other source of information, other than the utilities, that would guarantee that a notification of the right to opt out will be delivered to the customer of record. *[Se*e, e.g., Tr. 303-305.] As to load profile data, that information could be submitted by way of code (as it is in certain instances with regard to DA customers) that would still allow the potential CCA to evaluate its electricity needs and scheduling requirements. Therefore, it is abundantly obvious that name, address and contact information must be provided in a timely fashion by the utility to.the CCA in advance of a notification period and that load profile data can and must be provided, but possibly without specific reference to individual customer identification.

[CCSF] AB 117 states: "[a]ll electrical corporations shall cooperate fully with any community choice aggregators that investigate, pursue, or implement community choice aggregation programs. Cooperation shall include providing the entities with appropriate billing and electrical load data, including, but not limited to, data detailing electricity needs and patterns of usage, as determined by the commission, and in accordance with procedures established by the commission."[28] The plain meaning of this language is to allow a CCA to obtain and use information it needs to conduct its business.

CCA planning for power delivery must occur some months prior to commencing power deliveries. This will involve contracting in the long, medium, and short-term for power deliveries. This CCA planning will be severely compromised by lack of information regarding the likelihood of large customer opt-out from the CCA program. Hence, CCAs require basic customer data (name, address, contact information) for all larger customers (above 200kW or 500kW for example) to provide CCAs with the opportunity to survey these customers regarding opt-out intentions.[29] As Dr. Barkovich testified that, in her experience representing large electricity customers, they are concerned about the confidentiality of their electricity usage and not about the release of names, addresses, and contact persons at their business facilities.[30] Indeed large customers would appreciate knowing that CCA formation was being considered and would like to know what services a CCA might provide.[31]

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[28] PUC §362.2(c)(9).
[29] RT at 820.
[30] RT at 747.
[31] Id.

In order to appropriately investigate and implement a CCA program, a CCA needs basic load and usage data. Confidentiality agreements with adequate penalties can be developed to ensure CCAs do not abuse their access to customer data. Other approaches may work as well. For example, a bonded third-party service provider could receive the customer data, aggregate it in a way that ensures customer confidentiality, and then provide the aggregated data to the CCA to allow the CCA to adequately prepare for start-up.[32]

SDG&E's proposal is unworkable and contrary to the clear meaning of the statute. Under SDG&E's proposal, CCAs would know their customers only by an identification number.[33] SDG&E's provided rationale for this proposal is that "current Commission policy dictates that the utility is prohibited from releasing confidential customer information without signed written authorization (or pursuant to a subpoena signed by a judge)."[34] SDG&E witnesses do not cite this "current Commission policy," nor do they attempt to justify how a customer's name and address are "confidential customer information" under this unspecified Commission policy. This proposal contradicts AB 117's clear instruction that that it is the CCA's decision regarding how best to notify customers of their right to opt-out of CCA service. By withholding this basic customer information, the CCA would have no choice but to use the utility for opt-out notification rather than conducting the opt-out notification process themselves as allowed by law.[35]

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32 Exhibit 30 at 15.
33 Exhibit 3 at WK-3 to WK-4.
34 Exhibit 15 at JRM-11.
35 See PUC § 366.2(c)(13)(B).

PG&E agrees that if customer confidentiality can be protected through this Commission proceeding then CCAs can perform the notification process.[36] CCSF believes that the Commission can create adequate safeguards, such as a confidentiality agreement, to protect confidential customer information.

[LGCC] The IOUs have proposed a number of rules that unreasonably and unnecessarily limit the ability of Community Aggregators to obtain vital customer load information both before and after the CCA program is implemented. For example, the IOUs propose that if prior to CCA formation, Community Aggregators require information on customer load other than a single data point of total load for each customer class, the information can only be obtained on an aggregated basis of at least 15 customers in an assigned category, and no customer's load can be more than 15% of an assigned category (15/15 Rule). And, under the IOUs' proposals, the data provided pursuant to the 15/15 Rule must exclude information pertaining to customers with demands greater than 500 kW (500 kW Rule). In addition, Community Aggregators cannot obtain customer names or other important information even after the establishment of a CCA.

The primary result of these proposals would be to deny Community Aggregators the market information that is absolutely necessary to establishing and maintaining viable CCA programs. This result is in direct conflict with the IOUs' affirmative legal obligation to "cooperate fully with any community choice aggregators that investigate, pursue, or implement" CCA programs. The IOUs' proposed rules on customer information are anti-competitive and interfere with the

[36] Reporters transcript at 307.

contractual relationship between the Community Aggregator and the consumer. Ultimately, these rules do not serve the customers' bests interests but rather the interests of the IOUs in preserving their monopoly status.

i) Pre-Formation Customer Information

The IOUs propose that prior to the formation of a CCA, Community Aggregators would be required to inform the IOUs of their projected load and take the financial risk that the actual load deviates from the projected load. At the same time the IOUs propose to deny basic information to Community Aggregators regarding the loads which they must serve, including information on customers with loads over 500 kW. In other words, the Community Aggregators would be required to take on risk without having the tools necessary to mitigate the risk or potentially to even understand the scope of the risk. This would likely translate to higher commodity costs due to the uncertainty about the size and usage patterns of the load. In the worst case, these rules could prove to be an insurmountable obstacle if it is impossible for the Community Aggregator to forecast load.

The IOUs' proposals cannot be justified as necessary to protect consumers because there are much less restrictive means for providing load data to Community Aggregators while protecting the privacy of consumers. One simple and obvious method is to provide customer-specific data that does not include information that would enable the Community Aggregator to identify specific customers. SDG&E witness Keilani testified that SDG&E already provides customer data with no identifying information. This is a reasonable compromise that meets the needs of the CCA but still maintains customer privacy. The Commission has already approved a similar approach in Decision 03-07-034 in which it required the utilities to mask sensitive information or to release the information subject to a nondisclosure agreement. Another method is to designate third party data providers to provide data to prospective Community Aggregators. If the Commission is unwilling to allow the IOUs to release this redacted information directly to CCAs without prior consent from each and every customer, the Commission must establish a process by which the CCA's legitimate data needs can be met.

SCE argues that the 15/15 Rule must apply because the rule was designed to protect customers in the competitive direct access environment where there are multiple Energy Service Providers (ESPs). SCE argues that CCA is similar to direct access because ESPs will compete to become partners with Community Aggregators and are therefore in competition with each other to provide services to the Community Aggregator. SCE offers no proof for its assumption that all Community Aggregators will work with ESPs or its assertion that ESPs "have already played a major role in the formation of CCAs, often taking a lead position in the request and analysis of customer information." This argument must be rejected as pure speculation. Even if it were accepted at face value, SCE offered no proof or example of harm to consumers as a result of Community Aggregators contracting with ESPs for services.

For its part, SDG&E speculates, without any factual basis, that because Community Aggregators are cities they must already know the identity of customers with load greater than 500 kW so there is no need to get the information from the IOUs. Ultimately, SDG&E's position boils down to this -- "this whole thing is about an inability of the utility to release customers' information without the permission of that customer." However, even SDG&E has stated that if the Commission ordered the utilities to release the customer information, prior customer notification could be an adequate safeguard.

Both SDG&E and SCE failed to address the substance of the testimony of Witness Monsen that CCA is fundamentally different from direct access. The fact that Community Aggregators are cities and counties, not private companies that may not be headquartered in this state, is sufficient to establish the difference. Community Aggregators have a strong incentive to maintain good relationships with their customers – who are also their constituents – and to protect their privacy.

ii) Post-Formation Customer Information

Even after the CCA program is formed, SDG&E proposes to withhold customer information in the name of maintaining customer confidentiality. This proposal is at best curious given that the Community Aggregator has a direct contractual relationship with the customer. There is no legal or practical basis for affirmatively preventing the Community Aggregator from obtaining basic information, such as the identity of its own customers. There is no precedent for such an intrusion into contracts that are not regulated by this Commission.

Moreover, this proposal is inherently anti-competitive given that the IOU is the direct, and possibly only, competitor of the Community Aggregator. The IOUs would have wide latitude to interfere in the Community Aggregator/customer relationship, impose unreasonable costs as the price of that interference, and potentially hamper the Community Aggregator's ability to fulfill its obligations under AB 117. This interference is particularly troubling in the context of shut-off notices and special needs customers. The Community Aggregators would be forced to rely on the IOUs for vital communications with their customers and the IOUs have no incentive to prioritize such communications.

The Commission must ask the question, from whom should the customer be protected? The customer's Community Aggregator, which is likely the same entity as the publicly elected city council? Or the primary competitor and monopoly provider of data services to the customer's supplier? The Commission should adopt PG&E's proposal to automatically release customer information to the Community Aggregator when the customer is transferred to CCA.

G. Proposal for Third Party Data Services

There is no need for Third Party Data Services to be ruled on in this proceeding, except to the extent that such parties, as disclosed in an implementation plan, would as market participants face restricted access to confidential information as per EPS.

[LACV] Some of the parties have suggested, as a half-way measure to deal with the confidentiality issue addressed above, that third party services be utilized. The County and City believe that such services are unnecessary. However, if the Commission believes that such information cannot be provided directly to CCAs, then the third party provider is a potentially better solution than utilization of the utilities themselves as agent for the CCA. Utilities must be expected to do whatever is necessary to maintain their customer base and deprive the CCA of those customers whom the utilities have identified as being most valuable and whose information it has protected from view in the direct access program. Thus, the utilities are conflicted at best and not an appropriate agent.

[CCSF] CCSF does not believe that a third party data service is necessary because the Commission has adequate authority to require appropriate customer confidential information be held in confidence by the utilities and the prospective CCAs. Once a CCA is delivering power to its customers, all appropriate customer confidential information will and should be under the control of the CCA.

[LGCC] The IOUs have proposed a number of rules that unreasonably and unnecessarily limit the ability of Community Aggregators to obtain vital customer load information both before and after the CCA program is implemented. For example, the IOUs propose that if prior to CCA formation, Community Aggregators require information on customer load other than a single data point of total load for each customer class, the information can only be obtained on an aggregated basis of at least 15 customers in an assigned category, and no customer's load can be more than 15% of an assigned category (15/15 Rule). And, under the IOUs' proposals, the data provided pursuant to the 15/15 Rule must exclude information pertaining to customers with demands greater than 500 kW (500 kW Rule). In addition, Community Aggregators cannot obtain customer names or other important information even after the establishment of a CCA.

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V. COST RESPONSIBILITY ISSUES

A. Transaction Costs

[Local Power]

1. RECOVERABLE COSTS

The Commission should clarify the restrictions placed on costs a utility may collect from CCAs, and reject proposals to collect costs that are not attributable to a single CCA.

SDG&E focuses on the word "ANY" in the provision, "It is further the intent of the Legislature to prevent ANY shifting of recoverable costs between customers" (SDG&E Reply Briefs with their emphasis, p.23) but ignores the word "RECOVERABLE" as if it were less significant, when it is in fact the crux of the matter.

As to what is recoverable, this language in AB117 is restrictive, as SDG&E admits, to costs that are "reasonably attributable" to a CCA. (SDG&E Reply Briefs, p.2). In certain cases, as when "(a)ny costs not reasonably attributable to a community choice aggregator shall be recovered from ratepayers, as determined by the commission.(PUC 366.2c17) Then AB117 defines that reasonable transaction costs shall in all cases be charged to ratepayers. All reasonable transaction-based costs of notices, billing, metering, collections, and customer communications or other services provided to *an aggregator or its customers* shall be recovered from the aggregator or its customers on terms and at rates to be approved by the commission (PUC 366.2c17).

Thus, non-transaction costs or any costs CCA-related costs not reasonably attributable to any CCA should be excluded the definition of cost shifting, and the CCA's transaction-based costs should be derived exclusively from this group. Furthermore, AB117 provides that *either* the CCA *or* its customers shall have to pay these costs - thus the system for paying for these costs must be adaptable to either the ratepayers paying it (i.e. on monthly bills as they pay for all other services) or the CCA paying it (i.e. up front). *Thus, it is unlawful to suggest that the CCA should have to pay for all costs up front irrespective of its wishes, as this would obviate its option of having the ratepayers pay for the services that are essential to the service they have chosen as members of a community.*

PG&E has indicated support for all ratepayers to pay for basic implementation costs (PG&E Initial Briefs, p.53) agreeing with Local Power that such costs are not attributable to any one CCA (PG&E p.53). Local Power applauds this position and even supports the proposed true-up of the transaction charge, as it would be a charge born equally by all ratepayers and thus not threaten to prejudice a CCA's contracted rates relative to bundled service customer rates[37] But

[37]- unlike the CCA CRS true up proposal, which could have unpredictable impacts on the ratio of cost-of service utility rates and considerably more risk-bearing ESP rates to a CCA - creating a conflict of interest for the utility to take unfair competitive advantage in violation of AB117's requirement that utilities "cooperate fully" with CCAs (PUC 366.2(c)9) rather than undermine them as competitors, which all three utilities have asserted they are.

this true up underscores the importance of allowing “loans” as this form of true up is itself a “loan.”

PG&E proposes Exceptional Implementation Costs as a fourth category (PG&E Opening Briefs, July 9, 2004, p.55). These are defined as “services required to provide functionality beyond that of the basic implementation package.” We support the principal that elements not contained in a CCA’s implementation plan should be considered exceptional and be repaid by the CCA in the same manner s as all eligible costs - either by ratepayers on a monthly basis or their CCA up front, according to its choice.

Yet the utilities’position is inconsistent on what they consider forcing the ratepayers to “loan” the money to ratepayers whose communities do Community Choice. The utilities argue that the CCA “First Adopter” such as San Francisco in PG&E’s service territory, Los Angeles County in Edison’s service territory, or Chula Vista in SDG&E’s service territory should pay for any such transaction costs reasonably attributable to the CCA - “transaction-based costs of notices, billing, metering, collections, and customer communications or other services provided to an aggregator or its customers shall be recovered from the aggregator or its customers on terms and at rates to be approved by the commission.

2. REQUIRING CCAS AND FIRST ADOPTERS TO PAY FOR TRANSACTION COSTS UP-FRONT VIOLATES AB117.

PG&E opines that "CCAs should pay in advance for exceptional services and service establishment services. This is standard Commission-approved practice in many areas where the utility does significant work for a customer"(Opening Brief, p.69). [38] PG&E would include new metering work among these, even though metering work is specifically required by AB117 (PUC 366.2c18). PG&E claims that "(i)f advance payment or adequate security is not required, then ratepayers generally are financing the CCA's operation by fronting the money"(PG&E Opening Brief, p.70).

A monthly payment option is required by AB117. In addition to establishing the option of paying up-front for transaction costs (by the CCA), AB117 requires that the option be maintained that these costs must be recoverable from the CCA ratepayers through their rates. It matters not so much whether ratepayers enjoy the benefit of a "loan" from the ratepayer revenue pool in order to amortize payments through the rates - clearly the Commission has set many precedents in which the electric utilities benefit from "loans" from the ratepayers, who finance their very existence. CCA ratepayers remain utility captive utility customers for a range of services (default service, all customer service, billing, metering) so there is nothing inconsistent with giving them the rights of ratepayers to benefit from the revolving loan fund. This should not be limited to OOR or distribution accounts because the utility continues under statute as provider of last resort. AB117 establishes a permanent relationship between customer and the utility:

[38] It is interesting to note here that PG&E is referring to CCAs as "customers," contradicting their position that CCAs are Load Serving Entities and competitors relative to the application of confidentiality rules to CCAs. (PG&E Witness Sandra Burns, June 7, 2004 Evidentiary Hearing, p.454 line 22 to p.455 line 27; also S.G.&E Witness Jim Magill, June 8, 2004 Evidentiary Hearing, p.542, lines 6-9))

> Customers that return to the electrical corporation for procurement services shall be subject to the same terms and conditions as are applicable to other returning direct access customers from the same class, as determined by the commission, as authorized by the commission pursuant to this code or any other provision of law. Any reentry fees to be imposed after the opt-out period specified in this paragraph, shall be approved by the commission and shall reflect the cost of reentry. The commission shall exclude any amounts previously determined and paid pursuant to subdivisions (d), (e), and (f) from the cost of reentry. (366.2c11)

Thus, all accounts should be available to provide the "loan" from bundled service customers to ratepayers participating in a CCA in order to facilitate the statutorily required option of having ratepayers pay for those costs on their electric bills, as all other costs under consideration are paid, including the Competition Transition Charge, the undercollection charge for costs associated with the 5% rate cap in AB1890, the DWR obligation, and the Edison/PG&E bailout charges - not to mention the bonds that now underwrite the budget crisis. With the total charged on the ratepayer's monthly credit line now approaching $100 billion, it would be wrong to deny ratepayers that dare to implement CCA access to these funds in transactions exponentially smaller than what the utility shareholders now routinely receive.

Finally, to exclude ratepayers from access to the funds that violates other sections of AB117 - first a requirement that utilities co-operate fully with CCAs that investigate, pursue or implement AB117 (PUC 366.2c9), and second, a requirement that the Commission "shall take actions as needed to facilitate direct transactions between electricity suppliers and end-use customers"; and third, would violate the right of customers to aggregate (PUC 366.2a1) by requiring up-front payments in advance of investigation, pursuit or implementation, and (4) would violate the authority of CCAs, notwithstanding the Commission's actions, to negotiate with ESPs, as negotiation would be barred prior to an up-front payment to the utility.

[LGCC] All three IOUs stated that they do not know if they used consistent assumptions in developing their transaction and information fees, and that a coordinated exhibit, using the same assumptions for services, at the very least "could be useful". [39] PG&E witness Evans explained:

> Based on my experience with the direct access evolution over the last seven years, six years, I would argue that it's critical that we meet with intervenors and develop in Phase 3 a series of consistent services for CCA and transactions required in that – in that process.
>
> I don't believe, as was stated earlier or yesterday from Southern California Edison, that anybody should expect that every utility will have exactly the same transaction and/or exactly the same cost.[40]

It is critical that the Commission ensure that the IOUs use a uniform methodology for calculating fees that is vetted and approved by the Commission. A uniform methodology is necessary not only to ensure equal treatment of Community Aggregators and their customers across the IOUs'

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[39] RT 283: 9-13; 285: 12-13; 318:12-28.
[40] RT 318:20-28; 319:1.

service territories, but also to ensure that the calculation of the transaction fees are not a black hole that is impenetrable to all but the IOUs.

Also, LGSS agrees with the statement of PG&E Witness Helgen that the CCA transaction fess should "reflect any kind of savings that might also accrue" as a result of the CCA transaction.[41]

The Commission should order the IOUs to prepare a Joint Exhibit applicable to all three IOUs that: (1) details the services to be provided; (2) details the IOUs' proposals for providing these services, (3) and provides cost information on current tariffs for similar services to direct access customers.[42] Any decision on the actual level of the fees should be made in Phase II of this proceeding, and if necessary to prevent the delay of the implementation of CCA, use the direct access tariffs as an interim proxy measure.[43]

This Joint Exhibit will allow the Commission to compare costs across utilities. The Commission should require the IOUs to provide information on the charges that a CCA would encounter were it to obtain these services from third-party vendors.[44]

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[41] RT at 336: 3-18.

[42] Exh. 29, at 20.

[43] If the Commission wishes to adopt fees prior to Phase II, LGCC would support an order in the Phase I decision that the IOUs file a joint advice letter similar to the Joint Exhibit set forth above. However, we do not feel that the record in Phase I supports adoption of the actual fees proposed by the IOUs in their Phase I testimony and that further work, either via an advice letter or Joint Exhibit, is needed to ensure greater consistency.

[44] While AB 117 requires that IOUs continue to provide metering and billing services under CCA, there are other data management and software services for which CCAs may choose to seek competitive bids (Exh. 28, at 12).

1. Treatment of Implementation Costs

[Local Power] Implementation costs not attributable to a CCA or a CCA customer must be paid by all ratepayers. (PUC Section 366.2 (c)17) An electrical corporation shall recover from the CCA any costs reasonably attributable to the community choice aggregator, as determined by the commission, of implementing this section, including, but not limited to, all business and information system changes, except for transaction-based costs as described in this paragraph. Any costs not reasonably attributable to a community choice aggregator shall be recovered from ratepayers, as determined by the commission. All reasonable transaction-based costs of notices, billing, metering, collections, and customer communications or other services provided to an aggregator or its customers shall be recovered from the aggregator or its customers on terms and at rates to be approved by the commission.

[LACV] As stated throughout this brief, the County and City believe that certain transaction costs are appropriately assessed by the utility on the CCA. Implementation costs are not truly transaction costs. However, if implementation costs are treated as transaction costs, they should not be assessed if they are either (a) included within the distribution component of rates currently paid by all customers and that will continue to be paid by the CCA customer after switching to CCA service, or (b) are not assessed on direct access or bundled customers as individual service charges. Based on the testimony, such charges can be justified. Arguments that all charges are “incremental” are not plausible. Such arguments are inconsistent with Exhibits 48-50. For truly incremental transaction and other services, Ex. 24 provides a supportable charge.

In that regard, the County and City believe that implementation costs should not and cannot be assessed on CCA customers. Currently, utilities recover all direct access program implementation and start-up costs through Account 376 [Tr. 146]. That account is then spread over all remaining customers and paid in the distribution charges. As with information fees, implementation fees were not charged direct access customers who were provided basic information and start-up programs at no cost to them or their ESPs. Justification for this treatment was that the direct access program is the creation of a statute the Commission was required to implement. The exact same rationale applies to CCA, as AB 117 is also a statutory program which the Commission is required to implement through issuance of general rules and review of specific implementation plans tendered by the CCAs.

[CCSF] AB 117 requires the costs of generic system changes to be recovered from all ratepayers. "Any costs not reasonably attributable to a community choice aggregator shall be recovered from ratepayers, as determined by the commission."[45] CCSF regards these Category 1 costs as analogous to the incremental costs to implement the direct access program for which DA customers were not charged.[46] SCE’s and SDG&E’s proposals to charge CCAs for all

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[45] PUC §366.2(c)(17).
[46] Exhibit 30 at 9.

conceivable new costs created by CCA are not consistent with AB 117 or with the Commission's own understanding from the OIR that "[a]ny costs of program administration generally would be included in utility rates."[47] Furthermore SDG&E's proposal to charge the first CCA for all system based incremental costs would establish such a large first cost barrier that it would be unduly prohibitive for the first CCA.[48]

CCSF agrees with PG&E that basic system changes (i.e. changes to computer software, changes to internal PG&E work flows necessary to incorporate CCAs into PG&E's metering, accounting, and billing processes) should be charged to all ratepayers.[49] The IOUs should identify only the *incremental* costs associated with the implementation of CCAs. In addition, if ESPs or direct access customers did not pay equivalent costs, they should not be paid by CCAs. If the Commission decides that some costs should be charged to CCAs, the incremental costs associated with establishing the CCA program could be recovered through a memorandum account as proposed by CCSF witness Fulmer.[50] The CCA Establishment Memorandum Account or "CEMA" would account for costs not attributable to any specific CCA. In particular, the CCA program establishment cost should not born by the first CCA in a utility's service territory.[51]

[CalCLERA] Utility shareholders should be expected to bear a fair share of the costs of implementing Community Choice Aggregation.

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47 OIR, October 2, 2003 at 11.
48 Exhibit 31 at 4.
49 Exhibit 12 at 5-3.
50 Exhibit 30 at 10.
51 Id. at 16 to 17.

As noted elsewhere in this brief, CalCLERA believes that its time to end the blame-game over the event of 2000-2001. As also noted, CalCLERA believes that all California interests should participate in the solution, including the acceptance of a fair share of the costs.

The IOUs have attempted to pit bundled customers against customers of community choice aggregators, taking the position that they should not bear a fair share of these costs:

> Q Doctor, we are running short on time. I would have to ask you to be more direct. I'm asking you that -- are you contending that the utility shareholders should not bear a fair shore -- fair share of these costs?
>
> A That is what I'm contending. I don't see anywhere on AB 117 that says utility shareholders should bear a portion of those costs.
>
> Q So transcending whether you are legislatively required, you are further stating that on behalf of Edison that Edison is unwilling to absorb a fair share of those costs through the utility shareholders?
>
> A That is correct.

The plain language of AB117 confers no such language and the Legislature did not intend to immunize utility shareholders from bearing a fair share of these costs and risks.[52] Therefore, when the Commission determines "fair shares" of the costs and risks, it is not restricted to choosing between customers of community choice aggregators and bundled customers.

2. Incremental Costing Methodology

Local Power supports the principal that fixed costs be recovered from all ratepayers, not just the CCA, and that only certain incremental costs be recovered from CCA -- incremental transactions

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52 Tr. 1037 (Fenn).

costs attributable to CCA or CCA customers that may therefore recovered from the customers of the CCA.

However, incremental costs that are not specifically attributable to a CCA or its customers must also be recovered from all ratepayers.

[LACV] The County and City specifically object to the incremental costing methodology proposed by the utilities. This is a mechanistic effort to create charges against CCAs making CCA service potentially uneconomic. As an example, utilities propose that services that are.currently provided free of specific charge due to their costs being recovered in distribution rates, would be charged to CCA customers and then credited back to all distribution customers, including those very same CCA customers.

This process would further require a continuous evaluation of the time of each individual employee and the appropriate hourly charge associated with each individual employee in providing such services. The logical extension of the utility-proposed methodology is to totally unbundle all services, including all CCA, direct access and bundled services such that each individual customer pays for only those services that they receive at the time at which they request it. To single out CCA customers for such incremental costing methodology exceeds reasonable ratemaking expectations and would provide for a constant and unreasonable obligation of the CCA to monitor all utility operations and charges.

[CCSF] CCAs should only be charged fees for services that incur an incremental cost. CCSF agrees with SDG&E that past DA decisions should provide the proper guidance for determining incremental costs of providing CCA services.[53] Costs associated with an individual CCA should be charged to that CCA, except for costs deemed by the Commission to be "learning curve" in nature, which should then be charged to the CEMA or recovered from all ratepayers.[54] The CEMA would be recovered over time from several CCAs. The exact nature and terms of a CEMA account can be developed during phase 2.

There may also be costs associated with utility practice under direct access that may not be appropriate under CCA. For example, it may be more appropriate for PG&E's bill presentation and processing fee reconciliation to be charged under the account assistance fee category. The remaining activities, such as updating the CCA subaccounts, would be covered under the bill presentation and processing fee.[55] CCSF recommends that the specifics of which costs are included under which specific category be addressed in phase 2 of this proceeding.

3. Commission Oversight of Charges to CCAs

53 Exhibit 22 at 8.

54 Exhibit 30 at 17.

55 RT at 779.

[Local Power] As I stated in my Opening Testimony (Paul Fenn, Local Power, April 15, p. 4), the Commission should limit CCA CRS obligations according to an annual "Integrated Resource Calendar" (IRC) under which the Commission can plan, triage and coordinate between CCA load departures and electric utility procurement according to a uniform schedule. We propose that the Commission employ an IRC to circumscribe and annually modify its utility procurement forecasting, AB57 authorizations and energy efficiency funds allocations based on annual CCA notifications/compliance with the IRC including specific planning and implementation deadlines that are specified in my testimony. Under such a process, we have proposed that the Commission limit AB57 electric utility procurement authorizations to allow 5-10% of statewide aggregate investor-owned utility customer load to depart from electric utility procurement each year (Paul Fenn, Local Power, April 15, 2004, p.11). At a minimum, the Commission should use its discretion to exempt CCA's and CCA customers from any electric utility procurement that would encroach on this 5-10% CCA load departure window. In addition, the Commission should use its discretion to exempt CCA's and CCA customers from any electric utility procurement authorized after a CCA has approved an ordinance as outlined in section 366.2(c)(10) (A) for an individual municipality or county, and 366.2(c)(10)(B) for Joint Powers Agencies formed by multiple municipal and/or county jurisdictions.

[Local Power] **<u>COMMUNITY CHOICE ORDINANCE PROVIDES VALUE FOR ELECTRIC UTILITY PROCUREMENT PLANNING</u>**

Because the Commission has discretion to apply a CCA CRS exemption under certain circumstances, it has the implied authority to define under what conditions it will grant CCAs exemptions, including notification requirements in both the statutorily required CCA ordinance and the statutorily required CCA implementation plan. The CCA ordinance approved by San Francisco provides a useful example of how a CCA ordinance might provide the Commission and the utility with basic planning tools. Attached, please find the City and County of San Francisco's "Ordinance establishing a Community Choice Aggregation Program," (San Francisco Ordinance Number 86-04) passed by the San Francisco Board of Supervisors on May 11, and signed by Mayor Gavin Newsom on May 27 (Attachment 1). This document not only declares San Francisco a CCA, but it also includes a number of specific bidding requirements. First, the ordinance indicates that an Electric Service Provider's prices must include the cost of installing 150 Megawatts of n new wind capacity, 107 Megawatts of load reductions from new conservation and energy efficiency installations, and 104 Megawatts of new Distributed Generation such as fuel cells including 31 Megawatts of solar photovoltaic cells. The ordinance specifies that the Electric Service Provider, not the CCA, must post a bond or demonstrate insurance to cover the potential cost of an involuntary return of customers to Pacific Gas and Electric. Finally, the ordinance establishes a nine-month schedule for adopting an Implementation Plan and Request for Proposals that are consistent with the ordinance. These details offer significant planning tools to the Commission and Pacific Gas & Electric in their AB57 procurement process - tools that eliminate uncertainties (and related costs) associated with a particular CCA. The Commission has discretion to improve on the San Francisco ordinance template in order to eliminate any other uncertainties (and related costs) associated with a particular CCA. Should it do so, any remaining costs from utility procurement would be not associated with any particular CCA, but would rather be costs that are inherent to having CCA as a bundled service customer entitlement - and thus may be born by bundled service customers without causing cost shifting as defined by AB117.

[LACV] AB 117 anticipates limited Commission involvement with CCA programs. This is consistent with the Constitutional provision that allows communities to form municipal utilities and provide service.2 The involvement anticipated by the statute is that laid out by the Commission in its order instituting this matter and the scoping order by the Presiding Administrative Law Judge. However, as described in some detail in the cross-examination of Mr. Hansen on behalf of SDG&E [Tr. 570-579; see also Tr. 169-173], the utilities anticipate a detailed and thorough Commission oversight and the required involvement of CCAs in numerous utility proceedings. In effect, the utilities have presented an overly complex rate structure for charges such as the CRS, and propose a regulatory structure that would require CCAs to be involved in multiple and ongoing proceedings. This is clearly not the intent of the legislation and is designed solely to stifle CCAs. Cal. Const. Art. XI, § 9(a)..17

Among the many proceedings that are anticipated by the utilities for CCAs are at least one, if not two, further phases of this proceeding to establish actual rates and charges for implementation in transactions. The County and City believe these issues were the subject of this phase, and implementation rules are to be addressed in Phase II. No other phase is anticipated or necessary. IOUs have also encouraged the separation of the administration of Public Goods programs addressed in AB117 into multiple tracks, the affect of which is to make it financially unreasonable for most local jurisdictions to participate in all AB117 issues, and the rest to pick and choose where they can participate.

The utilities suggest that the CCAs must be involved in the annual DWR revenue requirement proceeding (proceeding 1) as well as the annual CRS calculation proceeding (proceeding 2). The second of these two proceedings involve CRS charges for direct access, distributed generation, municipal departing load and CCA customers. Each CRS class, however, will have slightly different issues and treatment. This process could also involve the yearly establishment of, or changing of, the CCA CRS. A CCA CRS subproceeding to implement "vintaging" on the indifference calculations by looking at all generation requirements on an annual basis, is also suggested (proceeding 3).

The utilities also assume a balancing account proceeding for CRS is needed to adjust the over or under collection from early years (proceeding 4, or part of 1 and 2) and CTC costs in the annual ERRA proceedings (proceeding 5). The utilities propose that over time, they may establish new charges or modify the charges that they are addressing within this proceeding. That would involve participation by the CCAs in the utility's general rate case (proceeding 6) and potentially advice letter filings (proceeding 7) to adjust individual charges or create charges consistent with the treatment for direct access service.

Further, the utilities currently are required to provide by July 9 a proposal for how CCA would be adjusted within long term resource planning proceedings and that such proceedings.will occur yearly thereafter. Clearly, such proceedings will be time consuming and contentious if CCAs disagree with assumptions made by the utilities, a situation that can be reasonably expected. This proceeding may also address the "vintaging" calculation (proceeding 8). Finally, SDG&E proposes an "open season" process each year for the CCA to state its expected load (proceeding 9). SDG&E appears to suggest that such a process also be subject to certain charges and that such charges will need to be "trued-up" based on previous year over or under estimations.

This listing of 9 or more proceedings is merely a sampling from the cross-examination of the testimony of utility witnesses, particularly Mr. Hansen for SDG&E. The County and City believe that such extensive, continuous and multiple overlapping proceedings cannot possibly be the intention of the legislation nor the Commission in its rulemaking establishing CCA service. Such an outline of procedures also fully supports the testimony, in part, of the Local Government Commission Coalition to unbundle CRS charges for all customers, whether direct access, community choice aggregation or bundled service [Ex. 28, 29]. Such an unbundling would allow each customer to see a menu of services with a fixed charge that is assessed against them for services rendered to them on an equal and non-discriminatory basis.

The County and City believe, unfortunately, that the procedure associated with DWR costs is unavoidable. However, the many other proceedings are totally avoidable. As an example, charges for CCA service, to the extent established, should be addressed within the utility general rate case exclusively and not be subject to a myriad of modifications. At a minimum, such myriad proceedings raise notice and due process issues with regard to CCAs and the utility providing distribution service to it. A simple approach may be to establish a single CCA proceeding per year per utility to address the various matters that the utilities now propose to roll into longer, more complex and potentially unrelated proceedings.

[CCSF] The Commission should require the utilities to provide documented transaction cost estimates prior to the implementation of any CCA. The Commission should review the activities to determine that they are indeed incremental to the formation of a CCA program and are appropriate to be charged to the individual CCA. The implementing utility must keep to this estimate, with any overruns reviewed by the Commission on a case-by-case basis. The starting assumption concerning CCA transaction fees should be that a CCA will not be liable for any particular cost until the utility has demonstrated to the Commission that the service is incrementally needed to serve the CCA or customers taking services from the CCA and that the cost to provide that service is not currently being recovered through rates.[56] Furthermore, if there are any savings that arise from cost efficiencies resulting from incremental or transaction costs paid by CCAs, these savings should flow back to CCAs.

4. CCA Fees and Existing DA Fees

CCA fees should reflect the lower transaction costs in relation to DA fees and any costs not attributable to a CCA customer may not be paid by that customer (PUC Section 366.2(c)17).

[LACV] As stated earlier in this brief, the Commission itself established that service by a CCA isidentical to direct access service in many respects. (Language quoted on p. 3.) The Commission itself proposed to apply the direct access service rules and service agreements to CCA.

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[56] Exhibit 30 at 4.

In cross-examination of Ms. Osborne on behalf of SDG&E, a comparison was made of the 39 proposed charges to be assessed community choice aggregation by the utilities to those charges that are assessed to direct access customers, and in some instances, bundled customers. [Tr. 636-652.] The exercise used Attachment A to Exhibit 22 which implemented and superceded the utilities' "strawman proposal." In this review, Charges 5, 16-18, 20-30 and 33-39 are charged to DA or bundled customers in one form or another. It should be stressed that charges 16-18 and 20-30 relate to consolidated billing services and providing information.

However, the first two requests for information by the customer or service provider are free and billing costs are included in current rates. Charges 33-39 apply to metering services. No one in this proceeding has questioned billing and metering charges except if costs for such are already collected in rates. AB117 provides for collection of such charges (see language quoted on pg. 13).

Exhibit 24, however, provides for a detailing of the services and specific charges that are assessed against direct access customers by SDG&E. In this proceeding, the utilities have proposed numerous charges which are neither assessed against direct access customers nor are they assessed directly against bundled customers but are collected through the distribution component which CCA customers will pay. [See Ex. 48, 49, 50.] The utilities have indicated that had they been given the opportunity they would have revised the direct access rules and that the direct access charges are dated. However, the direct access rules are the direct access rules. They are the rates, term and conditions of services the Commission has approved and at levels which the Commission has determined are appropriate..In this proceeding, after listing numerous charges and proposing various methodologies, the utilities do not actually propose any particular charge but suggest that yet another phase be implemented in this proceeding to establish those charges. [Ex. 23 at 6.] The County and City believe the Commission should maintain its original intent and provide that the charges associated with direct access service -- both as to amount and category -- be applied to service to community choice aggregators. To the extent to which the utilities wish to create additional services for both categories of customers, CCA and DA, they should apply for such within their general rate cases, justify an appropriate revenue requirement and propose a cost allocation for such services, rather than creating an amorphous charge and crediting arrangement.

In effect, the utilities hide behind the argument that AB 117 provides for no cost shifting. As discussed above, the majority of these services for which charges are now proposed to be assessed are currently collected in rates. [Exs. 48-50.] Others, not currently collected in rates are established by way of charges which the Commission has approved for direct access service. [Ex. 24.] The final category are costs for implementation which the Commission has determined, as to direct access service, should be borne by the ratepayers and have been accrued within Account 376. This reasonable treatment for direct access and bundled service should be extended to community choice aggregation. Any other proposal will merely protract these proceedings and delay AB117 implementation even further.

[CCSF] CCSF agrees generally with PG&E's proposal that CCA customers pay an identical or close to identical fee for those services where DA customers are charged. However, CCAs should not be singled out for special call center billing. For example, PG&E cannot bill direct access customers or their actual or prospective energy service providers for calls to PG&E's call center.[57] Customers calling utility call centers with questions concerning distributed generation are not billed, nor are their actual or prospective distributed generation providers. Call center costs are best addressed in the utilities' respective general rate cases and should not be parsed out through special usage fees.

In this proceeding, PG&E proposes to charge CCAs $4.38 per call for CCA inquiries. CCSF opposes such a charge as being unreasonable and contrary to current utility practice.Additionally, it is likely that the customer opt-out notification will be the first CCA information item sent to CCA customers. It will direct customers to call the CCA call center for answers to CCA related questions.[58] The utility call centers should also direct CCA inquiries to CCA call centers. Without such a clear demarcation regarding customer calls, many ambiguous cases could well end up being charged to a CCA. For example if multiple topics are discussed on a call, only one of which is CCA then apparently PG&E could bill the CCA for the entire call.[59] If a customer calls about CCA service but does not live in the CCA service territory, the CCA will be charged for this call as well under PG&E's proposal.[60] CCSF believes the Commission would not wish to audit the utilities at this micro level of detail and recommends the Commission reject proposals to charge CCAs for phone inquiries.[61] Should the Commission decide to accept the utilities' proposals to charge call center inquiries to the CCA CCSF believes that CCA call centers should also be allowed to charge utilities for non-CCA related electric utility inquiries (i.e. calls regarding outages due to storms).

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57 RT at 347.

58 Exhibit 30 at 21.

59 Exhibit 31 at 9.

60 Id.

61 Id.

5. Incremental Billing Costs

[LACV] Direct access service has provisions for billing services provided to direct access customers. Again, using the Commission's own philosophy, such costs for billing services are included in existing utility rates. There is no reason why such rates and methodology should not be applied to CCA service. If such services are incremental, the DA rate schedules, such as Ex. 24, provide an established rate for such services.

[CCSF] PG&E should provide a degree of unbundling of CCA billing costs such that CCAs can determine whether the costs of a specific service are commensurate with the benefits for the CCA or its customers. PG&E proposes to charge CCAs 70 cents/bill/month. For San Francisco, the cost of bill processing by PG&E could be approximately $2.75 million/year.[62] CCSF in reply testimony questioned the cost of this bill processing[63] and in rebuttal testimony[64] recommended a charge of only 8.5 cents/bill/month. Subsequently Mr. Labberton of PG&E provided more information regarding PG&E's proposed charge in response to direct cross examination by PG&E's attorney.[65] As a result CCSF also introduced further direct testimony questioning the accounting treatment of these costs.[66] CCSF does not dispute here Mr. Labberton's assertions regarding the labor time required for PG&E to reconcile DA accounts. However, CCSF believes

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[62] Id. at 11.
[63] Id. at 13.
[64] Id. at 9 to 11.
[65] RT at 352 to 361.
[66] RT at 777 to 781.

this matter should be further considered in phase 2, and the Commission should not make a decision regarding the level of the bill presentation/processing fee for PG&E in this phase.

CCSF believes the labor costs described by Mr. Labberton should properly be categorized as "Account Assistance" rather than under the Bill Presentation and Processing category.[67] This should result in the Commission approving a far lower bill presentation/processing fee for CCAs in PG&E's service territory and provide CCAs with a clear economic signal regarding the PG&E labor costs involved in reconciling bills, thereby allowing CCAs to determine the cost-effectiveness of the reconciliation of customer bills for different customer types. For example, it may not be reasonable for a CCA to explicitly incur a $50 charge to reconcile a $4 difference in a $22 residential bill"[68] and if an ESP or a CCA were explicitly faced with the actual cost of performing the service, it may very well decide that simply keeping the estimated bill and truing up the difference in the subsequent month would make more sense. This is in fact the way PG&E does it currently with DA customer accounts.[69]

Fairness should apply to these account assistance fees. Where such account assistance is required due to a PG&E error, the CCA should not be charged for the assistance.[70] Similarly if an error by the utility causes the CCA to incur additional costs (e.g. to back-bill customers) than the utility should reimburse the CCA for these costs as well.

6. Incremental Opt-Out Processing Costs

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67 RT at 779.
68 RT at 780.
69 RT at 781.
70 Exhibit 31 at 15.

[LACV] This is the perhaps the most offensive of all the requests for charges by the utilities. With direct access, the customer choice to receive direct access service or return to bundled service is accomplished free of charge. Such a decision may, however, have significant cost implications associated with utility procurement on a return to bundled service. In the CCA program, customers are included within CCA service unless they specifically opt out. Such customers receive four separate notices of the opportunity to opt out plus, if SDG&E's request is granted, a fifth notice by the utility to be paid for by the CCA. [Ex. 23 at 11-12.] Despite such numerous notifications and opportunities, and despite such lack of precedent for charges associated with return to bundled service, the utilities propose to bill the CCA when a customer elects to be served by the utility, most likely in response to utility advertising supporting its service. There is NO rationale or justification which could support such treatment.

[CCSF] The law is clear that opt-out notifications are the CCA responsibility that it may delegate to the utilities. The costs of processing opt-out customers should remain with the utilities. CCSF anticipates that CCAs will work cooperatively with utilities regarding notification language. However utilities should not have veto power over how the CCA conducts its opt-out notification.[71] Furthermore the costs of processing opt-out customers should remain with the utilities, and are not a cost attributable to CCAs.

PG&E proposes a charge of $1.53 to process an opt-out customer.[72] However, PG&E does not charge ESPs a processing cost for customers who are returning to bundled service. By the same logic PG&E should not charge a CCA for the processing of a customer who chooses to return to bundled service.

71 Exhibit 30 at 20.

72 Exhibit 31at 7.

Once a CCA is formed, the residences and businesses within the CCA jurisdiction are legally CCA customers. CCSF believes this formation is achieved once the CCA files an implementation plan with the Commission. If a customer decides to opt-out of CCA service they are making an affirmative choice for an alternative provider (the utility). Because this is a customer choice to move back to the utility, the processing charge for customers who choose to opt-out should be charged to the entity to which the customer is moving.[73]

7. Actual versus Estimated Costs

[LACV] The CCA community agreed to phase this proceeding with a cost phase and implementation rule phase for a very specific reason. The CCA community wished to know what the price tag would be before it spent significant amount of time and resources on rules associated with implementation of a program which may on its face be uneconomical due to Commission-ordered charges. In this phase, the utilities were directed to provide specific rates and charges for the services they propose to render. The utilities now take the position that they cannot even estimate these costs and only propose various methodologies. [See Ex. 23 as an example.]

As discussed above, there are relevant and reasonable proxies to use for such charges, including charges for direct access service, treatment of costs associated with direct access start-up implementation charges, and the DWR CRS methodology. There is no reason to rely on estimated costs or to defer cost estimates to some later time..Further, having once established

[73] Exhibit 30 at 20.

such costs and charges, by use of existing just and reasonable charges and fees, the Commission can adjust these in general rate cases at the request of the utilities upon a showing of actual expenses. To the extent those expenses are associated with implementation, the County and City urge that they be collected within Account 376 and billed to all customers as were all DA program, start-up and implementation costs. To the extent that they are not implementation charges, and there is no specific transaction fee associated with such activity, it would be incumbent upon the utility to show, in its general rate case, (a) the costs associated with providing such service, (b) an appropriate revenue requirement for such service, and (c) justify the charge for providing such service.

8. Revisions to Estimated Service Fees

[LACV] During the course of this proceeding, the utilities suggested that estimated service fees be modified by the advice letter process. It was unclear whether such advice letter process would be to increase or decrease the number of charges as well as the level of such charges. Consistent with the direct access program, the County and City anticipate that the proposal is all inclusive despite the lack of a specific response at the hearings.

However, direct access charges have not been adjusted for many years, nor has there been a showing within a general rate case of the need to adjust those charges by way of additional revenue requirements for services rendered to direct access customers. [Tr. 281.] Therefore, in an effort to minimize the costs to CCAs and the utilities, it is appropriate to require that any revisions be handled within the general rate case process and not put a continuing obligation on communities to appear in numerous, and possibly overlapping, proceedings at the Commission. As an alternative, the County and City have suggested that there be an annual CCA proceeding to address all of the charges and fees that may be assessed against the CCA which could be contemporaneous with the proceeding to set the CCA CRS. *[See*, Section 3(A)(3) above.]

[CCSF] As the utilities gain in efficiencies in conducting CCA related services, cost reductions in service fees should properly flow through to CCAs.[74]

B. Cost Responsibility Surcharge

[Local Power] Because AB117 makes the implementation plan the basis on which a CCA CRS is calculated, the details of the plan are a phase I issue. It would be advisable for the Commission to clarify its expectations for the plan during Phase I, including "consumer protection procedures," as PG&E suggests (PG&E Opening Brief, p.69) and "rights and responsibilities of parties" which could be made to include details that will enable the Commission to determine the net costs of a CCA's load departure, improve the accuracy of forecasting for resource planning, and allow the Commission to minimize the creation of stranded costs in its electric utility procurement process ®.01-10-024), as requested by the Governor in his letter to President Peevey. (Exhibit 47, p.1).

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74 RT at 797 to 798.

[LACV] While the CCA CRS may be the largest amount of money at issue in this proceeding, the proposals for how it should be treated appear to be the least controversial. In general, the County and City fully support the testimony of Dr. Barkovich on behalf of the City and County of San Francisco. [Ex. 25, 26 and 27.] Dr. Barkovich's proposed methodology is not inconsistent with that proposed by the utilities and she, and she alone, proposes a specific CCA CRS. Dr. Barkovich's proposed 1.5 cent CCA CRS was not controverted by DWR in its testimony nor by the utilities themselves in their testimony or cross-examination.

[LGCC] The magnitude of the Cost Responsibility Surcharge (CRS) will be an important determinant in the success of CCA programs. The Commission has before it a disparate set of proposals for determining the CRS using a "CCA-In/CCA-Out" methodology. Different parties have different concerns about the accuracy of all or part of the CRS.[75] Unless it adopts an altogether different methodology, like the unbundling methodology advanced by LGCC and described in greater detail below, the Commission will find itself mired in a never-ending cycle of annual reviews, true-ups, and balancing accounts.

While AB 117 requires the Commission to approve a cost-recovery mechanism, it does not state that the Commission must use the same methodology it adopted for direct access customers subsequent to the passage of AB 117.[76] Section 366.2(c)(8) states: "No entity proposing community choice aggregation shall act to furnish electricity to electricity consumers until the commission determines the cost-recovery that must be paid by the customers of that community choice aggregation program." While the legislation is clear that there are certain costs for which

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[75] Exh. 29, at 21.

[76] AB 117 was enacted September 24, 2002. The DA-in/DA-out methodology was adopted by the Commission in D.02-11-022, November 7, 2002.

CCA customers should pay, nowhere in the legislation does it state that the Commission must use the same methodology for CCA that it uses for direct access.

Most parties agree that the CRS is a customer responsibility, not a responsibility of the Community Aggregator.

[CalCLERA] CalCLERA, through the testimony of Dr. Charles Cicchetti, has been quite clear that responsibility for past costs is a significant burden but that it is one that will have to be shared by many segments of society, including customers of Community Choice Aggregators. "The central idea is to spread these costs fairly and justly. The blame game is over. No reasonable person would do otherwise. Repaying these costs is a high priority. Departing utility load can not, and mostly does not, shirk from this common responsibility. This means that departing load that stays in California should not be exempted from paying its fair share of the burden. Equally important, California should avoid any renewed attempts by the investor owned utilities (IOUs) to monopolize customers. How we assess and collect this common burden without favoring IOUs is the critical question before the legislature and CPUC."

[77]The correct determination of the costs that belong in the CRS and a mechanism to ensure that they are applied in a manner designed for recovery of those costs and not used as a device to discourage the development of new generation and economic revitalization or used to suppress competition is essential.

CalCLERA submits that the CRS should be established on the following principles:

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[77] Exhibit 41, p. 3.

1. Certainty and Predictability. Business planning, particularly for major investment, requires some certainty. That is precisely the point that IOU's have made in asking the Legislature to enact AB117, and the point made by Governor Schwarzenegger in Exhibit 47. That point applies equally to Community Choice Aggregators. For that reason, the total amount of CRS should be established and fixed at the outset (Exhibit 41, p. 15).

Arguments against an up-front determination revolve around the concept of forecasting and the possibility that a forecast may later prove inaccurate. Nothing in AB117 prohibits forecasting and indeed the Legislature intended to permit the use of forecasting in determining costs.[78] Equally clearly, forecasting requires effort and has some degree of imprecision. That, of course, could also be paid of many of the decision-making processes used by the Commission. However, the importance of certainty and predictability for decision-making by community choice aggregators and their customers amply justifies the use of forecasting to establish an up-front CRS.

It is noteworthy that the IOU's have strenuously argued for up-front decision making with regard to their procurement planning[79] and for the same policy reasons community choice aggregators and their customers should receive similar treatment with regard to CRS.[80]

2.. No New Stranded Costs. Although a part of achieving certainty and predictability, but deserving of special mention, is the critical need to not add to stranded costs. This is also an objective identified by Governor Schwarzenegger in Exhibit 47.

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78 Tr. 1036 (Fenn).

79 Exhibit 47, p. 2.

80 Exhibit 40, pp. 14-15 (Cicchetti).

The commission should make it clear that IOUs will not be permitted to incur new liabilities which will later be imposed on the customers of community choice aggregators.

would not materialize. California would have competitive, monopoly IOU buyers, not a workably competitive long-term wholesale power market.[81]

3. Transparency. An important protection against manipulation of CRS for anti-competitive or other improper purposes can be achieved by requiring IOUs to reflect on their retail bills the CRS being imposed on bundled customers.[82] This was done with the Competition Transition Charge (CTC) and should present no significant administrative burden.[83]

[IVDA] For the purposes of this brief, the relevant portion of AB 117 is as follows:

> It is the intent of the Legislature that each retail end-use customer that has purchased power from an electrical corporation on or after February 1, 2001, should bear a fair share of the [DWR's] electricity purchase costs, as well as electricity purchase contract obligations incurred . . . , that are recoverable from electrical corporation customers in commission-approved rates. It is further the intent of the Legislature to prevent any shifting of recoverable costs between customers."[84]

81 Exhibit 41, pp. 3-4 (Cicchetti).
82 Exhibit 40, p. 1 (Cicchetti).
83 Exhibit 41, p. 6 (Cicchetti).
84 Pub. Util. Code § 366.2(d)(1). Unless otherwise noted, all subsequent statutory references are to the Public Utilities Code.

> Accordingly, AB 117 permits, and authorizes, the imposition of a fair share of CRS on retail-end use customers.[85] This imposition is a two-way street for all retail-end use customers, not just retail end-use customers that leave bundled service. The plain language of this statute necessarily states that the remaining bundled customers must also bear their fair share.[86]

The CPUC has stated that it is within the exercise of its authority to make "[t]he determination of what the fair share should be . . . ."[87] Examples of CPUC reasoning in making this determination are provided in several CPUC decisions dealing with customer generation departing load[88] ("CGDL"), municipal departing load[89] ("MDL"), and new municipal load[90] ("NML"). The common theme throughout the decisions appears to be that: (1) the imposition of CRS turns on whether DWR incurred costs on behalf of the customer;[91] (2) costs are not incurred if the customer's load was not included in the load forecast relied upon by DWR in making its power purchases; and (3) the CPUC has generally relied upon record evidence to provide a basis for determining whether a load in the forecast was relied upon by DWR in making its power purchases.[92]

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85 D.03-04-030, at 39.

86 *See, e.g.*, Breshears v. Indiana Lumbermen, 256 Cal.App.2d 245, 250 (1967); People v. Baker, 69 Cal.2d 44, 50 (1968).

87 D.03-04030, at 39.

88 D.03-04-030.

89 D.03-07-028.

90 D.03-08-076.

91 *See e.g.*, D.03-04-030, at 61, Finding of Fact 20 (stating that granting exceptions to CRS for 3000 MW of customer generation will not result in cost-shifting since costs for those MW were not incurred by DWR); *See also* D.03-07-028, at 22, Conclusion of Law 9 (stating that [some NML] does not result in cost-shifting to bundled customers if DWR did not include this load in its forecast of future utility load).

92 *See e.g.*, D.03-04-030, at 54.

Both SCE and PG&E, in their supplemental reply testimony, attempt to draw a false distinction between load reductions explicitly stated in the IOU forecasts, and "further reductions" to those forecasts made by DWR.[93] Although, CPUC decisions do draw a distinction between *implicit* forecasts and *explicit* forecasts of the IOUs, the CPUC never goes so far as to suggest that DWR incurred costs for a load when an investor-owned utility ("IOU") *explicitly* forecast that the load reductions would occur. Truly, the CPUC decisions exhibit the principle that if an explicit reduction was shown for a load - - in either the IOU or DWR forecast, then no cost was incurred by DWR and CRS should not attach to that load. For example, in denying exemptions to MDL, the CPUC found no basis for a CRS exemption due to the "lack of a record of ***any specific*** load forecast adjustment for MDL," not in just the DWR forecast.[94] In reaching its decision, the CPUC sought input from all parties and many sources, but was unable to grant an exemption when it found "no evidence of any ***explicit*** level of MDL the IOUs expected ***or*** that was ever included in DWR's forecast."[95]

The NML decision utilizes similar reasoning. In granting a limited rehearing, the CPUC "acknowledge[d] that to a limited extent, the record show[ed] that there was evidence that the utility did include some new municipal load in the forecasts that were provided to DWR."[96] And then based on that IOU forecast, the CPUC "determined that some limited exemption should be provided to new municipal load . . . ."[97] Hence, the NML decision provides another example that ***any*** record evidence of explicit load reductions might be sufficient, regardless of whether the

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93 *See* PG&E Supplemental Testimony, Exhibit 53, at 1-2. *See also* Edison Additional Reply Testimony, Exhibit 51, at 2-3.
94 D.03-07-028, at 38 (emphasis added).
95 *Id.* at.37 (emphasis added).
96 D.03-08-076, at 16.
97 *Id.*

reduction is mentioned in the IOU forecast or the DWR forecast. In other words, as long as a reduction was identified and quantified by either the IOU or DWR, the CPUC has concluded that DWR did not purchase power, nor incur any costs, for that load.

To violate this principle of requiring a nexus between cost incurrence and cost responsibility is to violate the cost shifting proscription of AB 117. This principle is in harmony with the policy of providing some CRS exemption to the explicitly identified load that departs bundled service if it can be demonstrated that the load was not included in DWR's load forecast. No cost shifting occurs because the cost responsibility properly *remains* with the bundled customers for whom the power was actually purchased by DWR. Bundled ratepayer indifference is ensured as their charges will *remain* just and reasonable consistent with Section 451.

1. DWR's Calculation and Modeling Assumptions

[LACV] As stated above, the County and City fully support the testimony and proposals of Dr. Barkovich and Mr. Monsen [Ex. 28, 29] with regard to the calculation of the community choice aggregation cost responsibility surcharge (CCA CRS). Certainly, the DWR calculations have been the subject of numerous proceedings before this Commission and have been revised repeatedly for years 2001 through 2003. The County and City believe that no CCA program, under the current schedule of this proceeding and based on past Commission treatment of CCA issues, will be in place before 2006, nearly four years after AB117 was signed into law. Certainly, by that time any issues related to DWR's calculations will have been fully aired and resolved.

[CCSF] CCSF agrees that the CCA-Out, CCA-In, Modeling approach will provide the most appropriate means to calculate an indifference fee.[98]

2. Relation of DA CRS and CCA CRS

[LACV] This issue is somewhat complex in that the calculation associated with direct access is related to recovery of costs that have been previously incurred but not paid on behalf of direct access customers. That is not the case with regard to CCA customers. Indeed, CCA customers, with the exception of some current direct access customers, have fully paid all historic

98 Exhibit 25 at 3 to 4.

procurement costs ("HPC") associated with Southern California Edison Company. Past power costs are collected by SDG&E through its CTC mechanism, which is a separately stated, .unavoidable surcharge. Only PG&E has an historic utility charge ("HUC") associated with uncollected power costs for existing customers. Dr. Barkovich, and others, suggest that this charge be separately stated and billed.

Any remaining balance associated with a direct access customer who elects to be served as a CCA customer can be transferred and paid by that customer through its billings. This again requires a separate statement of HPC responsibility independent of the DA CRS amount. However, based on past experience, SCE can easily calculate remaining obligations for unpaid HPC charges.

[CCSF] The CCA CRS and DA CRS should be separately calculated due to the vintaging aspects of the CCA CRS (that is the CCA CRS should vary according to the year in which the CCA departs from utility supply service). Due to DWR contract expiration over time as well as new commitments made by the utilities, the CCA CRS should be vintaged. CCSF recommends that all new CCA load which starts in a given year in a given service territory pay the same CCA CRS.[99]

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[99] Exhibit 25 at 13.

3. Treatment of New Utility Contracts and Vintaging of CCA CRS

[Local Power] TURN witness Michael Florio agreed with the concept of an Integrated Resources Calendar under which CCA implementation plan and exit fee assignment processes could be coordinated with electric utility procurement in order to avoid the creation of any new utility procurement-based CRS.

No party disagreed with Local Power that the current crop of CCA cities is 11% of the investor owned utility market, nor my recommendation the Commission should leave a 5-10% load departure window for IRC compliant CCA to depart, with customer transfers starting in 2006 (Paul Fenn Opening Testimony on the CRS and Utility Cost Issues, April 15, 2004, p.9).

ORA suggested that after 2013 no such charges should continue, ORA witness Steve Ross set aside the question about whether utility contracts in 2005 and a CCA subsequently formed and makes its binding commitment to leave in 2007. Instead he correctly asserted the operative question – not *whether* those contracts entered into in 2005 be included in the CRS calculation for that CCA, but instead how to mitigate the problem in answer to the Governor's direction to the Commission not to create future stranded costs: in Ross' words, "because the CCA and utility procurement has been so well integrated that utilities truly know years in advance not to procure for a CCA that is departing."

The mechanism for authorizing electric procurement should be resolved in the next few months in both R.01-10-024 and R.03-10-003. Being parallel processes deciding how electric utilities should enter into contracts and how CCA can enter into contracts, the Commission will create the mechanism for the new hybrid world of CCA and utility procurement in these two proceedings (and R.01-080-28 re incentive ratemaking and the availability of energy efficiency funds to CCA). Mr. Ross urged the Commission "to not simply -- I think that an annual proceeding where a CCA tells a utility a year in advance -- that might not even be enough. That in an annual proceeding, any CCA, potential CCA, could inform the utilities of several years' worth of procurement plans or migration plans. And by 2013 I would like to see that set up sufficiently so that there would be no New World portion of CRS.`(Office of Ratepayer Advocate Witness Steve Ross, June 10, 2004, p.843 line 27 to p.845 line 11).

Local Power agrees with Mr. Ross that multi-year planning is necessary, but we assert that while CCA formation is an approximately 2-year process, an annual window allowing a percentage of bundled service load to depart without a CRS penalty. Given that the current crop of CCA cities (Local Power Witness Paul Fenn Opening Testimony, April 15, Attachment A) has formed over the past year, the Commission should include adequate short-term procurement in each utility's procurement plan to leave a window open for the current crop of cities to complete their opt out periods and depart from bundled service in starting in 2006 without any utility procurement or Utility-Retained Generation-related CRS, provided that the CCA submit implementation plans to the Commission in an orderly manner. Local Power recommends that CCA submitting plans by February 14, 2005 be allowed to depart without a CRS starting May 11, 2006. Moreover, we believe that URG presents major inconsistencies, and under AB117 URG is not be included among the CCA CRS obligations listed in 366.2(f).

[LACV] As stated in Section III(B)(8)("CAPS"), the County and City are very concerned that utilities will over contract for power to create added costs for potential CCAs under Section 366.2(f). Indeed, it appears that at least SDG&E is intent on such a policy.

The County and City recommend that the long-term resource planning process now underway as directed by AB57 should determine what contracts may be considered under Section 366.2(f) for inclusion in any CCA CRS. The passage of an ordinance, as well as active participation in this process, should be adequate to put the utilities on notice that its long-term contracting must consider CCA load for such communities.

The CCA CRS, however, may be vintaged for each CCA as it declares its intent based on then existent contractual commitments. However, an individual CCA should not have multiple CCA CRSs for community load, especially as the utilities argue that the CCA has an obligation to serve all load within its boundaries. [See, Section II(A) above.]

[CCSF] The CCA CRS should be vintaged according to the year in which a CCA begins power deliveries (irrespective of whether or not a CCA phases in deliveries of power to its customers).

Assuming the CCA has met the Commission's requirements regarding reserve adequacy, utility contracts entered into after the formation of the CCA should be excluded from the CCA CRS calculations.[100] CCSF agrees that the CCA should inform the utility of its best estimates regarding its intent to leave utility service and the date of its departure, so as to reduce or eliminate any negative impacts on remaining bundled customers.[101] If necessary the pending CCA should have an opportunity to reach an agreement with the utility to have temporary resources serve the CCA customers in lieu of adding any firm resources to serve a CCA load that would be shortly departing.[102] However the CCA's need to meet any resource adequacy requirement to meet its load should depend upon the timing of its departure.[103]

[LGCC] There is agreement in principle among the parties that CCA customers should not bear the cost of IOU generation contracts signed after the customer leaves IOU service. SCE states that CCA customers should not pay for the “New World generation” if proper switching rules are implemented.[104] SCE and PG&E state that the Commission’s imposition of resource adequacy standards that all load serving entities must meet by 2008 should eliminate the need to charge CCA customers for New World Generation.[105]

In the direct access proceeding the Commission adopted the so called “Switching Decision” imposing certain conditions of service on customers that move from direct access to

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[100] Reporters transcript at 717.
[101] Exhibit 25 at 13.
[102] Exhibit 25 at 13 to 14.
[103] RT at 723 to 724.
[104] Exh. 7, at 15.
[105] Id.; Exh. 12 at 2-8; See D.04-01-050, at Ordering Paragraph 2.

bundled utility service, and vice versa. For example, the customer is required to provide six months prior notice of return to IOU service or pay the spot market price for six months and is required to remain on IOU service for a minimum of three years.[106] The Commission found that these rules provide adequate notice to the IOUs and prevent cost shifting to IOU customers.[107]

The IOUs' inability to adjust their portfolios in response to shifts in customer load without creating additional costs is the same regardless of whether the returning customer is a CCA customer or a direct access customer. There is no reason why similar rules on switching would not adequately protect IOUs against load fluctuations caused by returning customers.[108] There is no need to reinvent the wheel by creating a new charge.

The Commission should be extremely wary of requiring customers to pay for generation resources that they will never use. As SCE pointed out, "CCAs, just like all other Load Serving Entities, should not be entitled to a non cost-based payment by the customers they are not serving because they make an economic choice for their own customers."[109] SCE's comment regarding LSEs applies equally to IOUs. This is a fundamental shift away from the Commission's traditional cost-causation approach to ratemaking and should not be adopted where there are other alternatives. To the extent that the DWR Power Charge is inconsistent with cost-causation principles, the Commission should not treat that single charge as the pathway to divorcing utility rates from any relationship with costs and benefits. The decisions

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[106] D.03-05-034, at 39-40.
[107] Id, Findings of Fact 10, 12 and 14.
[108] Exh. 7, at 15.
[109] Exh. 8, at 9.

imposing Assembly Bill 1X were an extraordinary response to an extraordinary situation and should not be applied to every situation.

4. Open Season Proposal

Local Power proposed the concept of an Integrated Resource Calendar under which certification of the CCA's Implementation plan and assignment of a CRS would be used to schedule CCA load departures with a minimum 5-10% annual CRS-free window, and the Commission orders a margin of short contracting by utilities as a cost not attributable to any particular CCA or CCA customer – but the cost of having CCA as a recourse to all bundled service customers.

[LACV] SDG&E proposes to establish an annual open season process by which a CCA nominates its load for the coming year. SCE supports this proposal. The County and City believe that the proposal may appear, at first glance, to have merit but is duplicative of the long term resource.planning process which the Commission anticipates each utility to engage in. If, as required by AB57, 3 the utilities have an annual long term resource plan which includes the planning associated with load for community choice aggregation, then an open season process is unnecessary.

[CCSF] CCSF believes that the open season proposal has merit. Furthermore, SDG&E made this proposal to allow all CCA departing loads to be combined with a common obligation for a single CRS. With a known open season period, there could be better coordination of utility resource planning and CCA activity. Such coordination would ideally reduce the concern about the responsibility of CCA customers for unnecessarily-added utility resources, with resulting benefits for all customers.[110] Furthermore attempting to have a different CRS for every single CCA "when it gave the definitive indication of departure would be administratively cumbersome."[111]

5. Provider of Last Resort

[Local Power] Under AB117, the utility is provider of last resort in that CCA ratepayers are entitled to return, whether voluntarily or involuntarily, to bundled service, and to be received by the utility. Once enrolled in a CCA, any ratepayer that chooses to opt out within 60 days or two billing cycles of the date of enrollment may do so without penalty and shall be entitled to receive default service pursuant to paragraph (3) of subdivision (a). Customers that return to the electrical corporation for procurement services shall be subject to the same terms and conditions as are applicable to other returning direct access customers from the same class, as determined by the commission, as authorized by the commission pursuant to this code or any other provision of law. Any reentry fees to be imposed after the opt-out period specified in this paragraph, shall be approved by the commission and shall reflect the cost of reentry. The commission shall exclude any CRS charges previously determined and paid from the cost of reentry. (PUC Section 366.2(c)11)

While under the advent of new world procurement the electric utility preparing for a resumption of the role of Provider of Last Resort, California's electric utilities broke the regulatory compact

110 Exhibit 26 at 9.
111 RT at 717.

when the State of California assumed the financial burden of serving customers – and the CPUC ultimately even charged ratepayers for AB1890 rate caps. Thus, the legal significance of the Provider of Last Resort role has lost substance since 2000. In its January 22 decision, the Commission (1) directed that each Load Serving Entity (LSE) within the utility's service territory (i.e., utility, Energy Service Provider (ESP) or Community Choice Aggregator) has an obligation to acquire sufficient reserves for its customer's load located; (2) adopts a reserve margin for LSEs of 15-17%; (3) directs the LSEs to meet this 15-17% reserve requirement by no later than January 1, 2008, through a gradual phase-in including the establishment of interim benchmarks to become effective in 2005; (4) establishes a requirement that utilities forward contract 90% of their summer (May through September) peaking needs (loads plus planning reserves) a year in advance; and (5) continues the 5% target limitation on utilities' reliance on the spot market (i.e., Day-Ahead, Hour-Ahead, and Real-Time energy) to meet their energy needs. (CPUC Decision 04-01-050, January 22, 2004). Thus, the Commission has also shifted some of the traditional burden of the provider of last resort onto a CCA or indirectly onto its ESP.

[LACV] One thorny issue is whether the utilities provide a backstop to CCA service or whether the CCA is fully responsible for all the energy needs of its customer base. It is clear that the Commission, to some extent, will require that all load serving entities ("LSEs") maintain a margin of excess supplies available for service to their customers. Certainly, resource adequacy should be the responsibility of a community choice aggregator. However, operational reliability will remain with the utility as the utility will continue to operate the transmission and distribution wires necessary to have the adequate power delivered to the CCA customer, as with all customers.

Without specific agreement to a level of resource adequacy, the County and City believe that any requirement that LSEs have adequate resources should eliminate the concern and eliminate any potential charges associated with provider of last resort responsibility by the investor owned utility. Such levels of resource adequacy can be reported in implementation plans.

[CalCLERA] In particular, IOUs should not be permitted to incur additional power procurement costs on behalf of community choice aggregators under the guise that IOU will be the provider of last resort ("POLR"):

> Attempts to impose POLR costs on those departing customers that do not seek or require POLR protection would add unjustifiable additional costs on departing load. Doing so would assure that both CCAs and non-core or departing load customers would pay fees to IOUs that are not just or reasonable. Such POLR fees would also mean that non-core customers and cities that seek to break away from IOUs would pay penalties that are not justified. CCAs and non-core customers assume responsibility for their supply portfolio. They should not pay IOUs to provide the same services.
>
> The IOUs and their remaining customers also need protection from any future effects of departing load. The IOUs and their remaining customers should not be forced to guarantee future supplies or reliability for the non-core customers and cities that voluntarily depart. Legislative and CPUC polices should recognize these dual interdependent interests. At most, a stiff, return price should be levied to make this potential future cost transparent. In a perfect world, there would simply be no re-instatement or return rights. In a compromise, departing customers would pay no fees for POLR protection. However, the right to be reinstated would be conditional, including penalties. This compromise, not departure fees, is the best non-bypassable solution if California seeks to add non-core and new city-owned electricity providers, such as CCAs, to its re-emerging wholesale power market.
>
> Without such an approach, IOUs would be the only buyers of power and departing load (*i.e.*, CCAs and new wholesale buyers)

> would not materialize. California would have competitive, monopoly IOU buyers, not a workably competitive long-term wholesale power market.[112]

6. Proposal for Fixed CRS Obligation

[Local Power] By fixed CRS Obligation Local Power understands to mean a charge similar to that imposed on DA customers **-** a flat per kilowatt hour fee.

AB117 requires that the Commission inform a CCA's prospective customers what they must pay based on their CCA's specific implementation plan details. The Commission is required by AB117, after certification of receipt of a CCA's implementation plan and any additional information requested, the *commission shall then provide the community choice aggregator with its findings regarding any cost recovery that must be paid by customers of the CCA* to prevent a shifting of costs – a fee, based on Commission forecasting, which will not change for any CCA from year to year.

A flat fee-based per kilowatt hour CRS obligation is not allowable to the extent that it would ignore the particular details of a CCA implementation plan and thus fail to reflect benefits to bundled service customers.

Clearly, establishing the CRS at the outset involves forecasting. Nothing in AB117 prohibits forecasting and indeed the Legislature intended to permit the use of forecasting in determining

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[112] Exhibit 41, pp. 3-4 (Cicchetti).

costs (Local Power Witness Fenn, June 24, 2004, p.1036, lines 12-15) While forecasting requires effort by the Commission and involves some degree of imprecision, the importance of certainty and predictability for decision-making by CCA and their customers amply justifies the use of forecasting to establish an up-front CRS that will not involve a true-up.

It is noteworthy that the IOU's have strenuously argued (D.04-01-050, January 22, 2004, p.117) for up-front decision-making with regard to their procurement planning, and even while preserving their right to recover costs from their ratepayers no longer face after-the-fact regulatory review of their electric procurement contracts by the Commission under D.04-01-050 pursuant to AB57 and SB1976. With CCA requiring EPS to shoulder a greater degree of risk than the Commission requires of utilities, a CRS true-up is therefore unacceptable.

[**LACV]** The County and City believe that a fixed CRS is desirable but may not be achievable. he current methodology for CRS calculation requires a "tune-up" as well as recalculations ased on (a) an annual DWR revenue requirement calculation and (b) customer indifference calculations.

7. CRS Applicability to CCA or CCA Customers

Under AB117, a retail end-use customer purchasing electricity from a CCA shall reimburse the electrical corporation that previously served the customer for: (1) The electrical corporation's unrecovered past undercollections for electricity purchases, including any financing costs, "*attributable to that customer*," that the commission lawfully determines may be recovered in rates (PUC Section 366.2(f)1), as well as (2) any additional costs of the electrical corporation recoverable in commission-approved rates, equal to the share of the electrical corporation's estimated net unavoidable electricity purchase contract costs "*attributable to the customer"*, as determined by the commission, for the period commencing with the customer's purchases of electricity from the community choice aggregator, through the expiration of all then existing electricity purchase contracts entered into by the electrical corporation (PUC Section 366.2(f)2).

AB117 employs a broader standard to recover DWR bond-related costs (PUC Section 366.2(e)1) which states that ratepayers pay "(a) charge *equivalent to the charges that would otherwise be imposed* on the customer relative to DWR bond related costs, and for DWR contracts requires a CCA customer to pay "the customer's *proportionate share* of the Department of Water Resources' estimated net unavoidable electricity purchase contract costs" (PUC Section 366.2(e)2). Yet in the next paragraph the legislature employed more restrictive language regarding what CRS charges may be applied for utility costs – that such costs must be "attributable to the customer."

As AB117 does not provide for the CCA CRS to include new Utility Retained Generation, CCA may not be charged a CRS for URG.

[LACV] This issue has not been fully aired within this proceeding. The question, it seems, is whether the CRS responsibility – that is, bond charges, DWR contracts, and possibly, "new world" utility power contracts, is with the CCA or its customer.

The County and City believe that this issue should be resolved at the option of the CCA in the filing of its implementation plan. Certainly, this issue, as with the issue of the 130% of baseline exemption discussed later, relates to the establishment of rates by the CCA. CCAs are governmental entities which reserve the right to establish rates and charges independent of Commission regulation. Should a CCA wish to bear the CRS responsibility for all customers within its territory, and potentially finance the payment of such responsibilities, such an option should be available to them. However, CRS, as it is defined, relates to activities of DWR to obtain power to serve such customers prior to such customers being CCA customers. It is thus a cost responsibility of the individual customer who has received the benefit of those efforts. As such, should the CCA not elect to bear the responsibility for the CRS of its individual customers, such CRS responsibility should flow with the customer, especially if they elect to opt-out and return to bundled utility service.

However, if the CCA elects to bear the CRS responsibility of all of its customers, the subsequent opt out of CCA service by any customer should require the utility to reduce the CRS responsibility of the CCA or credit the CCA with any costs paid by the CCA for an early payment of such CRS responsibilities for that customer.

8. Proposed Cap on CCA CRS

[LACV] The County and City believe that if CCA CRS is limited to the DWR contract costs and bond costs, there is limited reason to cap the CCA CRS. In this regard, the County and City support the testimony of Dr. Barkovich. [Ex. 25, 26, 27.].However, with regard to both the County and City, the issue of capping is especially important with regard to "new world" power cost obligations that may be lumped on CCA customers. As an example, at SDG&E's recommendation in May of 2001, the City of Chula Vista has studied its procurement options in its extensive review of its options. The City, based on several studies and hearings, proposed to become a CCA, and issued the required ordinance.

Nonetheless, SDG&E has failed to reflect the existence of any CCA load in determining its need to enter into contracts, including purchasing long term power and generation assets. [See, D.04-06-011, "Opinion Approving ... New Resource Contracts ...," issued June 15, 2004.] Further, SDG&E has received approval for such contracts in advance of it reporting how it proposes to deal with CCA with regard to the required long-term resource plan submitted on July 9. In effect, SDG&E appears to be racing to establish contracts in a manner that will force CCAs to subsidize such purchasing decisions after SDG&E has refused to acknowledge that such purchasing decisions may be excessive to system needs due to creation of CCAs. This activity, if not checked, could make CCA service artificially uneconomic and should, at a minimum, support caps.

[CCSF] For PG&E the Commission should adopt a 1.5 cent/kWh CCA Cost Responsibility Surcharge (CRS) for 2005/2006.[113] Since this CRS is based on an evaluation of the DWR CRS projections, it is not a cap as commonly understood under DA. Rather it is a cap only insofar as

[113] Exhibit 25 at 7.

the CRS level would be fixed for two years.[114] Since this CRS is based on an evaluation of the DWR CRS projections, it is a reasonable forecast of the CRS for 2005/2006 that would apply to CCAs within PG&E's service territory.[115] The utilities have not provided any estimate of a CCA CRS in this proceeding, despite the ALJ's November 26, 2003 and January 29, 2004 rulings that convey the clear intent of the Commission to develop a CRS to be charged to CCAs).

Even though it was possible to calculate a recommended CCA CRS, the utilities have proposed taking up the question of a CRS calculation for potential CCAs in a future proceedings.[116] This is an unworkable solution given the clear mandate of the Commission and the ALJ to determine cost issues, to the extent possible, in Phase 1 of this proceeding.[117] Pushing this issue to other proceedings will not assist communities currently considering becoming CCAs.

CCSF's recommendation to cap the CRS charge at 1.5 cents/kWh will not create an immediate undercollection of CRS from CCA customers.[118] Rather, it is intended to create a degree of certainty for CCA planning.[119] Indeed CCSF's proposal is entirely consistent with D.03-07-030, which adopted the most realistic scenario for setting a cap for direct access customers.[120] Furthermore, if there is any undercollection due to the 1.5 cent/kWh CRS cap, it will be manageable.[121] As Dr. Barkovich testified, the "risk of an under collection in the early years must be weighed against the advantages that a cap will provide in the implementation of a

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114 See Exhibit 10.
115 Exhibit 25 at 9.
116 RT at 682 to 683.
117 See also letter from State Senator Bowen to Commissioner Peevey, dated 6/1/04 and Commissioner Peevey's reply dated 6/8/04.
118 Exhibit 25 at 7.
119 Id. at 5.
120 RT at 684.
121 Exhibit 25 at 5.

CCA.[122] The utility and ORA arguments that there be no "under collections" can only result in choosing a "systematic set of adverse assumptions in order to assure no under collection."[123] And "in order to assure that there will be no under collection you have to guarantee an over collection by using a series of extremely conservative assumptions, because otherwise, since you are forecasting, you are never going to know exactly what the right answer is."[124] Choosing such a path could only discourage CCA formation for many years.[125]

9. True-up of CRS Obligations

[Local Power] AB117 requires that the Commission inform a CCA's prospective customers what they must pay based on their CCA's specific implementation plan details. The Commission is required by AB117, after certification of receipt of a CCA's implementation plan and any additional information requested, the *commission shall then provide the community choice aggregator with its findings regarding any cost recovery that must be paid by customers of the CCA* to prevent a shifting of costs – a fee, based on Commission forecasting, which will not change for any CCA from year to year.

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122 Exhibit 26 at 2.
123 Id. at 5.
124 RT at 682.
125 Exhibit 26 at 5.

Clearly, establishing the CRS at the outset involves forecasting. Nothing in AB117 prohibits forecasting and indeed the Legislature intended to permit the use of forecasting in determining costs (Local Power Witness Fenn, June 24, 2004, p.1036, lines 12-15) While forecasting requires effort by the Commission and involves some degree of imprecision, the importance of certainty and predictability for decision-making by CCA and their customers amply justifies the use of forecasting to establish an up-front CRS that will not involve a true-up.

It is noteworthy that the IOU's have strenuously argued (D.04-01-050, January 22, 2004, p.117) for up-front decision-making with regard to their procurement planning, and even while preserving their right to recover costs from their ratepayers no longer face after-the-fact regulatory review of their electric procurement contracts by the Commission under D.04-01-050 pursuant to AB57 and SB1976. With CCA requiring EPS to shoulder a greater degree of risk than the Commission requires of utilities, a CRS true-up is therefore unacceptable.

[Local Power] <u>CCA CRS TRUE UP VIOLATES AB117</u>

A CCA CRS true-up has been proposed by the utilities as a solution to the forecasting uncertainty that is involved in calculating the CRS. While Local Power (Ex.44, p.23-4), Cal Clera/Cicchetti, p.14-15 and LGCC (Ex.28, p.38) have proposed a fixed CRS, PG&E claims that "given the unpredictability of future market conditions, determining a 'one time' rate would be contentious and protracted." PG&E Opening Brief, p.22).

First, this is a policy argument, not a legal argument. While determining a fixed CCA CRS may be controversial, it would be no less so than utility procurement, which rate-bases utility power purchase agreements and utility-retained generation based on forecasting at the expense and risk of bundled service customers.

Second, PG&E admits in the above quote that costs associated with market volatility are inherent to the market, not caused by CCA, any particular CCA, or any particular CCA's customer: Therefore, under AB117, sharing these costs associated with inaccurate forecasting in calculating a CCA CRS among all ratepayers would not constitute cost-shifting., but are, rather, costs that are intrinsic to having CCA as an option to all bundled service customers. As costs associated with future market volatility are not attributable to a CCA customer, they may not be included in the CCA CRS calculation.

Third but most important, the policy argument presented by PG&E is overridden by specific provisions in AB117 requiring a fixed CCA CRS.

a. AB117 FORBIDS A CCA CRS TRUE-UP

AB117 specifically requires the Commission to provide a CCA with a dollar figure CCA CRS following a 90 day implementation plan, information request and certification of a CCA's implementation plan. AB117 limits the CCA CRS to two forms:

> (1) The electrical corporation's unrecovered past undercollections for electricity purchases, including any financing costs, attributable to that customer, that the commission lawfully determines may be recovered in rates.
>
> (2) Any additional costs of the electrical corporation recoverable in

> commission-approved rates, *equal to* the share of the electrical corporation's estimated net unavoidable electricity purchase contract costs attributable to the customer, as determined by the commission, for the period commencing with the customer's purchases of electricity from the community choice aggregator, through the expiration of all then existing electricity purchase contracts entered into by the electrical corporation. (PUC 366.2 (f))

Both forecasts would thus have to estimate costs from utility undercollections and determine New World Procurement costs "equal to" existing electric purchase contract that are "attributable to the customer."

Both of these utility collections would be authorized at the discretion of the Commission:

> *In order to determine the cost-recovery mechanism* to be imposed on the community choice aggregator pursuant to subdivisions (d), (e), and (f) that shall be paid by the customers of the community choice aggregator to prevent shifting of costs, the community choice aggregator shall file the implementation plan with the commission, and any other information requested by the commission that the commission determines is necessary to develop the cost-recovery mechanism in subdivisions (d), (e), and (f).   (PUC Section 366.2(c)5)

Thus, AB117 hardwires the ability to recover a CCA CRS itself (subdivisions (d), (e), and (f)) to the implementation plan and other information the Commission requires of a CCA. Given that the CCA CRS will be tied to the specific proposal of the CCA, it follows that much of the data needed for estimating the actual impacts of a CCA load departure would be tied to these details. It would follow that the true-up being proposed would be based on the inaccuracy of the

Commission's determination of the cost recovery mechanism based on a CCA's implementation plan pursuant to 366.2(c)5. This plan is mandated to include the following:

(A) An organizational structure of the program, its operations, and its funding.

(B) Ratesetting and other costs to participants.

C) Provisions for disclosure and due process in setting rates and

allocating costs among participants.

(D) The methods for entering and terminating agreements with other entities.

(E) The rights and responsibilities of program participants,

including, but not limited to, consumer protection procedures, credit issues, and shutoff procedures.

(F) Termination of the program.

(G) A description of the third parties that will be supplying electricity under the program, including, but not limited to, information about financial, technical, and operational capabilities.

(4) A community choice aggregator establishing electrical load

aggregation shall prepare a statement of intent with the implementation plan. Any community choice load aggregation established pursuant to this section shall provide for the following:

(A) Universal access.

(B) Reliability.

C) Equitable treatment of all classes of customers.

> (D) Any requirements established by state law or by the commission concerning aggregated service.

A True-Up of this charge is forbidden by the section of AB117 that describes the Commission's certification of the implementation and assignment of a cost recovery mechanism to a CCA's implementation plan:

> "After certification of receipt of the implementation plan and any additional information requested, *the commission shall then provide the community choice aggregator with its findings regarding any cost recovery that must be paid* by customers of the community choice aggregator to prevent a shifting of costs as provided for in subdivisions (d), (e), and (f).)" (My emphasis, PUC 366.2c7).

Furthermore, subsection section f that is referenced (PUC 366.2f) indicates, again, that New World Procurement-related CRS *costs must be EQUAL TO the share of the electrical corporation's estimated net unavoidable electricity purchase contract costs attributable to the customer.." (See above for full quotation)* Thus, AB117 requires that the assignment of a CCA CRS to a CCA's implementation plan be a number - a *dollar figure.*

b. CCA CRS TRUE-UP PREVENTS TRANSACTIONS BETWEEN CUSTOMERS AND ESPs

PG&E claims that "the unsubstantiated assertion that CCA cannot be effectuated without a fixed CRS is extremely suspect":

> “because the resource mix (and cost of generation) between the utility and any CCA will not necessarily be the same, the utility’s generation costs and the CCA costs are unlikely to move in tandem. Merely fixing one variable (the CRS) would not materially aid in attempting to make long term rate comparisons.” (PG&E Opening Brief, p.23).

This is a rather bizarre argument resting on the grounds that no long-term rate comparison can be made anyway, so why not add greater uncertainty than there already is. In fact, CCA ratepayers will rationally compare rates of their ESP to utility rates, and will rationally determine and accept responsibility for the conditions of their service as they compare in the long run to utility services. The CCA CRS is not part of this choice, but, rather, a surcharge attached to the choice which a CCA needs to be fixed in order to make that rational, calculated decision. A fixed CCA CRS is a basic requirement of any CCA negotiating with an ESP. Without knowledge of a fixed CCA CRS , no CCA will know how an ESP’s agreed upon rates will impact its members’ electricity bills, and a rational choice between bundled service and an ESP’s proposed service would be obviated in violation of AB117.

Whereas pursuant to AB57 and SB 1976 utilities may rate base their power contracts or utility-retained generation, CCA ESPs will shoulder a far greater risk in providing service at agreed upon rates, terms and conditions, and therefore require transparent knowledge of electric bill impacts for the duration of their contracts. Thus, the Commission is required to provide a dollar figure CCA CRS, not subject to true-up, pursuant to the statutory order that it facilitate transactions between CCAs and ESPs:

"The commission shall take actions *as needed to facilitate direct transactions between electricity suppliers and end-use customers*". (PUC 366a).

A CCA CRS true-up would effectively prevent negotiation between ESPs and CCAs, and would violate the AB117 requirement that consumers be informed of the terms and conditions of a CCA program during the opt-out process.

c. TRUE UP VIOLATES CONSUMER PROTECTION STANDARDS

Unlike Direct Access, which employs an opt-in method in which each consumer affirmatively chooses a new supply, CCA employs an opt-out method in which the local governing board of a municipality or joint powers agency evaluates the offerings of Electric Service Provider on behalf of ratepayers (PUC 366.2a2) and makes a decision on their behalf. Whereas DA could and did cherry pick large and affluent customers, and excluded low -income ratepayers from participation as well as the vast majority of small residential and business ratepayers, CCAs have universal access requirements (PUC 366.2c4A) and must offer service to all residents (PUC 366.2b). As local city councils are making the affirmative decision by passing an ordinance (PUC 366.2c 10Aand 366.210B) to switch service on behalf of these more vulnerable customers, price transparency and stability are essential to negotiating CCA contracts.

> A community choice aggregator may group retail electricity customers to *solicit bids, broker, and contract for electricity and energy services* for those customers. (PUC 366.2c1).

Thus, fundamentally, a true-up violates basic consumer protection standards. State law requires that CCA customers be notified of the switch and the opportunity to opt out of the CCA.

> Any notification shall inform customers of both of the following:
> (i) That they are to be automatically enrolled and that the customer
> has the right to opt out of the community choice aggregator without penalty.
> (ii) The terms and conditions of the services offered. (PUC 366.2c13A).

Providing “terms and conditions” to a ratepayer considering whether to opt out is part and parcel of facilitating transactions between ratepayers aggregating their load through CCA and ESPs. The Commission is therefore required to ensure that the “terms and conditions” enable a consumer to judge rationally whether the net electric bill im pacts of a CCA program will be positive or negative. A true-up would prevent this judgement, inserting radical uncertainty into the net electric bill impacts of the services offered, and is therefore unlawful.

A true up would undermine the ability of CCAs comply with the Renewables Portfolio Standard law (SB1078, 2002-Sher). Parties agree that CCAs must comply with the RPS law, under which CCAs must procure according to a scheduled mix from the current statewide level of 13% to 20% by 2017 - an eight percent increase RPS compliant resources in the electric mix.

Given that the vast majority of the existing renewable resources are recently tied up in utility procurement contracts, RPS compliance will certainly mean the development of renewable resources and energy efficiency, which is also authorized in great detail by AB117.

d. TRUE UP PREVENTS CUSTOMER-OWNED GENERATION, EFFICIENCY AND CONSERVATION

A true up in the CCA CRS would impede the ability of CCAs to build customer-owned generation, conservation, resource efficiency and RPS acceleration requested by both the Governor (Exhibit 47, p.1) and the Commission-adopted Energy Action Plan:

9. "optimizing energy conservation and resource efficiency and reducing per capita electricity demand";
10. "(a)ccelerate the state's goal for renewable resource generation to 2010":
11. "(p)romote customer and utility owned distributed generation. (Energy Action Plan, Adopted May 8, 2003 by the CPUC, April 30, 2003 by the CEC, and April 18, 2003 by the CPA, p.2).

Unlike electric utility procurement and Utility Retained Generation, which under AB57 and Decision 04-01-050 (January 22, 2004) will win pre-approval to rate base power purchase agreements and even power plants without traditional Commission review of contracts and severely restricted access even to forecasting data, customer owned generation and the efficiency and conservation elements of CCA (PUC 381.1) will depend on a contract between the CCA and its chosen ESP (PUC 366.2c15). Security on this contract will be subject to a 120 day opt-out process (PUC 366.2c11 and 366.2c13) by aggregated ratepayers. A CCA CRS true-up would insert a radical additional uncertainty into CCA contracts that include customer-owned generation, conservation or energy efficiency components, potentially making such contracts impossible to negotiate, in violation of AB117.

[LACV] As discussed above, the CCA CRS methodology would include an annual true up. As further discussed above, a CCA CRS responsibility should follow an individual customer unless and until the CCA itself agrees to bear the responsibility for such costs, subject to crediting or repayment in the event that such customer subsequently opts out of CCA service.

[CCSF] Any forecast essentially becomes a cap, since the actual indifference costs attributable to CCA or DA load cannot be determined until after the fact. This is the reason for a true-up. This true-up can either increase or decrease the CCA CRS for the following period. A true-up will result in a make-up responsibility for the CCA customers if the forecasted CRS turns out to be too low and causes a shortfall in revenue below the actual indifference amount. If the concern underlying the utilities' proposals for no cap is taken literally, then the implication is that there can be no circumstance in which there is a shortfall in revenue from CCA customers through their CRS payments, when compared to the actual indifference costs calculated after the fact. This means that there must be an excessively conservative set of assumptions used to ensure that CCA customers overpay the CRS. In effect, this guarantees that bundled customers will be subsidized by excess credits from the CCA CRS revenues to the ERRA. This results in the very cost-shifting that AB 117 legislated against, only this time the cost shifting is to the CCA customers, not bundled customers. Such a biased forecasting process should not be adopted by the Commission. Thus, a set amount for a CCA CRS over some period of time (a cap) with true-ups and adjustments to the cap will give CCAs more cost stability and should be adopted.[126]

10. Load Factor Adjustments

[Local Power] The Office of Ratepayer Advocates (ORA) has proposed a load factor-based adjustment to the CRS mechanism to be imposed on CCA. Indeed, AB117 requires CCA-specific load profiles in calculating a CRS for any particular CCA for a number of reasons outlined below.

Under AB117, a retail end-use customer purchasing electricity from a CCA shall reimburse the electrical corporation that previously served the customer for: (1) The electrical corporation's unrecovered past undercollections for electricity purchases, including any financing costs, "*attributable to that customer*," that the commission lawfully determines may be recovered in rates (PUC Section 366.2(f)1), as well as (2) any additional costs of the electrical corporation recoverable in commission-approved rates, equal to the share of the electrical corporation's estimated net unavoidable electricity purchase contract costs "*attributable to the customer"*, as determined by the commission, for the period commencing with the customer's purchases of electricity from the community choice aggregator, through the expiration of all then existing electricity purchase contracts entered into by the electrical corporation (PUC Section 366.2(f)2).

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126 Exhibit 27 at 5.

AB117 employs a broader standard to recover DWR bond-related costs (PUC Section 366.2(e)1) which states that ratepayers pay "(a) charge *equivalent to the charges that would otherwise be imposed* on the customer relative to DWR bond related costs, and for DWR contracts requires a CCA customer to pay "the customer's *proportionate share* of the Department of Water Resources' estimated net unavoidable electricity purchase contract costs" (PUC Section 366.2(e)2). Yet in the next paragraph the legislature employed more restrictive language regarding what CRS charges may be applied for utility costs – that such costs must be "attributable to the customer."

Thus under AB117, CRS charges to a CCA's customers must reflect that CCA's peak load requirement costs, not merely reflect the peak load requirement costs of the average utility's customer, nor merely meet the utility's revenue requirements – as this would presume shareholders are protected against cost-shifting, which they are not. The utilities argument that they have always forced ratepayers from less peaky areas to subsidize ratepayers in peakier areas (PG&E Witness Andrew Bell, June 8, 2004, p.507 line 11 to p.508 line 8) does not make it legal to do so with the CCA CRS, which specifically forbids it.

SDG&E's witness admitted that using a utility's system average load profile-based CRS would not adjust a CRS for the CCA that have implemented aggressive energy efficiency and other peak load reductions despite the fact that such peak load reductions would have dramatically reduced costs associated with meeting their peak load requirements (SDG&E witness Robert Hanson, Evidentiary Hearing, June 8, 2004, p.609, Lines 16-17). If San Francisco implements its adopted ordinance requiring EPS to install 360 MW of load-reducing efficiency, conservation and renewable technologies in a community with 650-850 MW load, virtually perfecting its load profile as a region, it might at expiration of its CCA contract return its customers to bundled service for a time, then subsequently implement a new CCA load departure. Under this scenario, San Francisco's customers could not lawfully face the same CRS as a CCA of similar load departure history but which had done nothing to improve its community's load profile. (San Francisco's adopted Community Choice ordinance 86-04, approved May 27, 2004).

A system average load profile-based CRS directly violates the plainly worded requirement in PUC Section 366.2(f)2 that CRS charges on a CCA customers reflect costs that are "attributable to the customer":

- First, it would impose charges on CCA's customers based on peak load requirement costs that they have actively eliminated, such as in San Francisco.
- Second, a system average load profile would arbitrarily cost-shift between CCA and bundled service customers by directly imposing charges associated with peakier customers from one location in a utility's service territory on less peaky customers at another location in its service territory.

No less significant, failure to implement a CCA-specific load profile-based CRS would create a massive disincentive for CCA to implement peak load reduction efforts, jeopardizing fully half of the "means" identified by the adopted Energy Action Plan for meeting the Commission's adopted policy goal of meeting California's energy needs in an environmentally friendly manner:

· “optimizing energy conservation and resource efficiency and reducing per capita electricity demand”;

· “(a)ccelerate the state's goal for renewable resource generation to 2010”:

· “(p)romote customer and utility owned distributed generation. (Energy Action Plan, Adopted May 8, 2003 by the CPUC, April 30, 2003 by the CEC, and April 18, 2003 by the CPA, p.2).

[LACV] The County and City have no position on this issue.

11. Utility and CCA Procurement Risks

CCA risks relative to Utility Procurement is carefully circumscribed by AB117.

Under AB117, a retail end-use customer purchasing electricity from a CCA shall reimburse the electrical corporation that previously served the customer for: (1) The electrical corporation’s unrecovered past undercollections for electricity purchases, including any financing costs, “*attributable to that customer*,” that the commission lawfully determines may be recovered in rates (PUC Section 366.2(f)1), as well as (2) any additional costs of the electrical corporation recoverable in commission-approved rates, equal to the share of the electrical corporation’s estimated net unavoidable electricity purchase contract costs “*attributable to the customer”*, as determined by the commission, for the period commencing with the customer’s purchases of electricity from the community choice aggregator, through the expiration of all then existing electricity purchase contracts entered into by the electrical corporation (PUC Section 366.2(f)2).

AB117 employs a broader standard to recover DWR bond-related costs (PUC Section 366.2(e)1) which states that ratepayers pay "(a) charge *equivalent to the charges that would otherwise be imposed* on the customer relative to DWR bond related costs, and for DWR contracts requires a CCA customer to pay "the customer's *proportionate share* of the Department of Water Resources' estimated net unavoidable electricity purchase contract costs" (PUC Section 366.2(e)2). Yet in the next paragraph of AB117 the legislature employed more restrictive language regarding what CRS charges may be applied for utility costs – that such costs must be "attributable to the customer."

[LACV] The County and City believe that issues associated with procurement risks of the utility should remain with the utility and its customers. As discussed above, the County and City.believe that a CCA should bear no responsibility for any newly-executed procurement contracts effective after the establishment of the CCA. Establishment of a CCA is, as defined by statute, effective with the passage of an ordinance by the community or communities involved. Further, such "new world" costs should not be applicable to areas where no valid utility franchise exists.

Similarly, the County and City believe that the responsibility of CCAs for their power procurement decisions should be solely with the CCA and its customers. In this regard, the CCA may, subject to its own discretion, establish an exit fee for customers who may opt out after power is procured by the CCA on behalf of that customer. The switching rule provisions, that will be addressed in the next phase, may more particularly address this issue. However, if a CCA customers takes with it certain responsibilities to the utility, it is equally important that the customer take with it the responsibilities that were incurred on its behalf while it was a CCA customer if it elects to return to utility service.

12. Barriers to CCA Formation and Reflection of CCA Benefits

[CalCLERA] CalCLERA respectfully requests that this Commission:

1. determine the CRS on an up-front basis
2. require IOUs to display the CRS component applicable to IOU customers on their bills
3. use net costs in establishing CRS levels
4. prevent IOUs from incurring additional stranded costs
5. recognize cost reductions resulting from community choice aggregators which develop new generating resources in the form of a credit to be determined either in accordance with Dr. Cicchetti's recommendations or through a collaborative process.

[Local Power] With California CCA representing over ten percent of the investor-owned utility market are now spending scarce funds to implement programs with a minimum goal of 40% RPS, it is clear that CCA will deliver massive benefits to all bundled service customers in California, and their CRS should reflect that benefit.

Artificially imposing a “gross cost” definition on AB117 would violate AB117 and create a massive barrier to implementation by refusing to include elements in a CCA’ implementation plan that benefit bundled service customers in the calculation of the CRS.

Thus, in calculating a CCA’s CRS, the Commission should “net” such benefits against the costs imposed by the implementation plan.

CAL CLERA’s witness asserts that if a CCA achieves certain kinds of benefits for the bundled service customers who remain, then the Commission should be able to net those benefits against that gross cost assignment to the CCA so as to encourage formation of CCA and the encouragement of CCA that produce benefits for the entire state, including the customers who stay behind.(CAL-CLERA Witness Charles Cicchetti, p.965, lines 16-22).

Local Power agrees with Mr. Cicchetti that the definition of “costs” in AB117, as in all Commission nomenclature, is “net” costs, requiring a CRS equal to an amount paid out *less any related savings or money returned* - not gross costs in which the gross amount is paid without regard to savings or money returned.

In other words, the legislature intended that bundled service customers should be held harmless from the impacts of a CCA load departure on a net basis (CAL CLERA Witness Cicchetti, page 979, lines 25-27) – not be allowed to absorb all the benefits of CCA customers' investments, such as improved reliability, with one hand, while charging CCA customers for every cost associated with their actions with the other.

[Local Power]**CCA CRS SHOULD NET COSTS VERSUS BENEFITS TO BUNDLED SERVICE CUSTOMERS**

PG&E has indicated that benefits from CCAs that implement a 40% Renewable Portfolio Standard should not be credited to CCAs based on three reasons, each contradicted by simple legal facts:

a. Benefits are Material. PG&E claims that the benefits may not materialize or if they do bundled service customers may not benefit (PG&E Opening Brief, p.25). Yet, as with the assignment of costs to a CCA's implementation plan, "materialization" depends on the signing of a contract by the CCA, at which point it becomes legally binding to all parties. Meanwhile, the Commission has discretion to determine the dollar value of the benefits associated with the implementation plan.

b. Benefits are Comparable and Commission has Discretion to Make Determination. Second, PG&E claims that _proponents have not compared this benefit to utilities actions to determine whether bundled service customers would benefit (*Id*). Again, the Commission has discretion to compare the relative benefits and determine the net CCA CRS.

c. Benefits Offset Costs, Not an "Incentive." Third, PG&E claims that if the benefit does exceed the utility's actions, an adjustment to the CRS may not be the best means of "providing the appropriate incentive" (*Id.*). But the credit was not proposed as an "incentive"[127] but rather as a simple means of employing the Commission's standard "net" definition of costs in the term "cost-shifting" so that "costs" covered by a CCA CRS will indeed by "attributable" to a CCA customer based on that plan, and therefore be consistent with AB117. The Commission need not be concerned with incentives but with fairness and compliance with state law.

PG&E suggests that "to the extent that the Commission chooses to create incentives for certain public policy actions they should apply equally to CCAs and utilities on a systematic and uniform basis." (*Id.*, p.26) This is a curious double error in reasoning. First, PG&E is confusing a CCA CRS calculation method with the creation of a shareholder incentive framework - a different issue entirely. Second, under a net CCA CRS calculation, because the benefits of a net CCA CRS would go to CCA customers, so any credit from greener utility procurement, being paid for by utility ratepayers, would not lawfully go not to PG&E shareholders, *but to all bundled service customers.*

[127] The utilities are indeed seeking "shareholder incentives" before they will offer such "benefits" that CCAs are seeking voluntarily

PG&E disputes that CCAs have offered benefits in other states or that California CCAs already in formation would offer the benefits they have promised:

> The Commission should be extremely wary of claims that somehow an unregulated CCA is likely to be more benevolent to bundled ratepayers than an equivalent Commission-regulated utility....Instead, there has been no proof (other than stated intentions) that CCA either has provided these benefits in the past or will do so in the future." (*Id*., p.30)

Indeed, San Francisco has passed an ordinance *requiring* its implementation plan and Request for Proposals to include bidding requirements that qualifying ESPs build a massive renewables far above the levels required by the RPS law or proposed by PG&E, installing 360 Megawatts of solar, wind, efficiency and conservation for a CCA with 650 MW base load (San Francisco Ordinance 86-04, May 27, 2004). In Ohio, the 900,000 customers now being served through CCA include 650,000 customers whose switch from coal and nuclear to natural gas and renewables- powered generation resulted in a net 75% pollution reduction, and a 33% greenhouse gas reduction, virtually making them comply with the Kyoto treaty - all with no rate increase.

PG&E's position is a self-fulfilling prophesy. If San Francisco and the dozen California cities seeking a 40% RPS (which is a 28% increase over current levels rather the 8% mandated by SB1078) face an unfair CCA CRS that does not reflect the massive benefits of their programs to bundled service customers, they may indeed never materialize. However, if these benefits are reflected in the CCA CRS, early studies indicate they will be successful with no need for increased rates.

[LACV] The County and City believe that it is abundantly clear that the creation of a CCA will have direct benefits to the State of California. Numerous witnesses addressed the various benefits. [Mr. Orth in Ex. 39, Dr. Cichetti in Ex. 40, and Mr. Monsen in Ex. 28.] These benefits include expanding the market for new local, in state generation by unbundling transmission and generation interests, creating new customers for generation, expanding the potential for local generation, expanding the potential for renewables and "green power generation," and providing additional customer choice for service, equitably delivering the same benefits to "all" energy consumers that was proposed for large consumers under deregulation and is being proposed for even a more select few under the current core/non-core proposals. These "benefits" must be recognized and, indeed were well recognized with the passage of AB 117. The County and City, however, do not have a position on how such benefits can be calculated or reflected in lower charges from the utilities in the CCA CRS. Various proposals have been put forward including.percentage reductions. The County and City believe that some method related to a specific load or generation level that is added following the creation of the CCA that does not cause additional customer responsibility for "new world" generation or power contract costs in CCA CRS should be provided.

The Commission, however, can definitely remove "barriers" to the creation of CCA. The utilities have proposed numerous charges and convoluted, extensive, multiple and overlapping proceedings. The utilities also characterize the process by which the implementation plan is reviewed by the Commission as akin to an application pursuant to Section 1001 of the Public Utilities Code. In this regard, the County and City request the Commission to establish four principles with regard to removing utility barriers to creation of CCAs. (1) Charges currently recovered in rates should not be incrementally billed to CCA customers. (2) Charges not billed to comparable service, such as direct access service, should not be billed to CCA customers. (3) The Commission should limit the number of proceedings in which a CCA must participate, or establish an annual CCA proceeding to address charges and costs associated with a CCA program. (4) The Commission should not create unnecessary regulatory and cost barriers to the formation of CCAs.

[LGCC] LGCC Witness Monsen testified that CCAs provide benefits to all customers by reducing the IOUs' procurement risk, contributing to local reliability through the development of local generation, and contributing to statewide renewable resource goals.[128] PG&E Witness Burns acknowledged that if CCAs make system improvements that, for example, reduce transmission costs, these benefits will accrue to bundled services customers as well as CCA customers.[129] However, the CCA-in/CCA-out methodology only includes CCA benefits to IOU customers that result from the differences in IOU short-term spot purchases.[130] Witness Burns stated, "But I think going forward as we make longer term commitments, you would reflect longer term differences in procurement between the in and the out runs."[131] Although PG&E testified that benefits to the system could be accounted for by tweaking the CCA-in/CCA-out model, a much simpler method would be to exempt certain CCA load from the CRS if the CCA

[128] Exh. 28, at 8.
[129] RT 451: 7-12; 478:13-20.
[130] RT, 452: 25-28; 453: 1-3.
[131] RT, 453: 1-3.

can meet specific renewable or reliability goals based on measurable standards.[132] The Commission must implement rules that are fair and equitable to CCA customers as well as to bundled service customers, by requiring that the IOUs credit the CCA community for benefits in addition to charging them for costs.

[CalCLERA] It is critical to achieving the Legislature's intent in enacting AB117 that net costs be correctly calculated and assigned in the CRS.[133] The Legislature's intent (Tr. 1037; Fenn) and it is common sense. If a purchaser pays $20 for a product and receives $5 in change and a credit worth $5, the "cost" of the purchase is $10. The point is so basic that it ordinarily need not be made, except for the fact that the IOUs in this proceeding have refused to provide net cost information for the record, instead using gross costs. It is revealing that SCE uses the same concept in supporting its recent economic development incentive rate filing. Exhibit 41, p. 2 (Cicchetti), but concept seems to have largely disappeared from IOU consciousness in the instant proceeding.

For all community choice aggregators, CRS should reflect savings and other quantifiable benefits resulting from Community Choice Aggregation

Savings Verification

With regard to all costs (including fees) which IOUs propose to include in CRS or otherwise impose on the customers of community choice aggregators, IOUs should be required to provide verification, under oath, that they have made good faith reasonable efforts to determine the

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[132] Exh. 28, at 26.

[133] Exhibit 41, pp. 2-3 (Cicchetti).

benefits, cost reductions or other advantages to all electricity consumers in the State of California and/or local communities and/or the State of California in general from the formation or implementation of community choice aggregation, specifically including but not limited to, the effects of community choice aggregation in the following areas:

a) potential reductions in the cost of wholesale power resulting from potential stimulation of new electric generation plants in the State of California

b) potential reductions in the authorized rate of return resulting from reduced capital investment requirements for IOUs

c) improved IOU efficiency in procuring power

d) potential stimulation of economic development in communities which elect community choice aggregation

Savings to All Customers Resulting from Increased IOU Procurement Efficiency

Implementation of community choice aggregation will "encourage healthy … retail competition" as recommended by the Governor in Exhibit 47. IOUs will be facing both benchmark competition (between retail rates in a community that has elected aggregation and rates in surrounding areas) and head-to-head competition within a community. That competition will place IOUs under continuing marketplace pressure to be efficient in its procurement practices. Those efficiencies will redound to the benefit of bundled customers of the IOUs and to the benefits of the general economic climate in the State by reducing the cost of electricity.

Community Choice Aggregators which Develop New Generation

Cost Reductions Resulting from Reduced Wholesale Power Costs

A number of potential community choice aggregators including CalCLERA would like to develop new generating facilities to serve California consumers. If they are successful, all California electricity consumers will benefit from increased reliability and reduced costs. This can be illustrated with an example from the record.

[134] Assume that a newly formed community choice aggregator takes 500 MW of the load from the IOU's load (approximately 40,000 MW). If, rather than relying on the same sources of generation that the IOUs did to provide this generation, the CCA either secures alternate long-term supply sources from sources outside the wholesale market used by the IOUs or construct its own 500 MW generating plant, the effect would be to reduce demand in the wholesale market by the 500 MWs. This would, all other things being equal, cause the price in the market in which IOUs purchase more than two thirds of their energy for resale to be reduced. Eliminating 500 MW out of a total IOU wholesale market of about 40,000 MWs reduces total demand by about 1 to 2 percent. Using those reasonable assumptions it is likely that it would have a small effect on the price per MWH. When this small price effect is multiplied by the total number of MWHs the IOUs sell in California, the effect in terms of dollars saved by IOUs bundled customers can become very large. These savings will all accrue to the benefit of those customers that remain IOUs' customers.

This large dollar savings can be compared to the value of the CRS that would be extracted from those customers who departed the IOUs' system in favor of the new CCA. Again, let's assume a 500 MW plant with an 85 percent capacity factor. That plant would produce 3,723,000 MWHs

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[134] Exhibit 40, pp. 5-14 (Cicchetti); Tr. 940-942 (Cicchetti).

(500 * 8,760 * .85) per year. Assuming, solely for purposes of this illustration, a CRS of $27.50 per MWH, multiplied by the nearly four million MWHs would result in an annual CRS payment upwards of $100,521,000. Based on extensive experience with the energy industry, CalCLERA's witness, Dr. Cicchetti concluded that a 50% credit would be justified based on the following analysis: assuming at IOU demand in California of 40,000 MW, and 250 million MWHs per year, as a result of reducing demand across the wholesale market, a price reduction of $0.20 per MWH, (or .02¢ per kWh) wholesale costs for IOUs would be reduced by $55,000,000, or approximately 50% of the assumed base CRS. Stated another way, if the reduced demand on the system reduced wholesale market prices by 2/10's of one mill/kwh MWH, the savings across the entire system would justify the 50% credit.[135]

In addition, bundled IOU customers would benefit from the reliability benefits of new generation that is built to supply much needed capacity for California. Given the financial challenges admitted by IOUs, such additional investments, regardless of the precise calculation, would benefit remaining all California electricity consumers.

A further benefit is that some "new" customers which would otherwise not move to California if required to pay a CRS set at $27.00/Mwh, might be attracted to California. Such a "new" customer load that pays any portion of the CRS would reduce the burden of all others. Finally, CCAs that build new efficient and/or renewable energy systems, promote the state's well-being, and improve employment in the state would provide additional direct benefits for all electricity consumers.

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135 [insert cite to Charlie's suggestion of studies to refine the calculation]

Accordingly, Dr. Cicchetti has proposed a “pragmatic solution would take the following form for those CCAs that secure alternate sources of generation or build new generation to serve their customers:

- All former and current IOU retail consumers should pay a separately identified CRS fee transparent on their retail bills, regardless if they stay or not
- CCA customers that cause new supply for California should pay a CRS that is 50% less than the base DA CRS established by the CPUC;
- An additional 25% reduction from the base DA CRS should be granted to those CCAs located in high unemployment areas;

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An additional 25% reduction from the base DA CRS for those CCAs utilizing renewable generation (over the state-mandated RPS level) to serve their customers’ load.[136]

A credit to recognize these benefits and to stimulate the development of new generation is not cost-shifting. This point has been made by SCE and PG&E in analogous situation, their respective recent economic development incentive rate filings. Exhibit 41, p. 2 (Cicchetti). Both SCE witness Jazayeri (Tr. 1073) and PG&E witness Rubin (Tr. 1085-1086) explained how their proposed incentive rates did not involve cost shifting, despite the fact that certain customers

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[136] Exhibit 40, pp. 21-22 (Cicchetti).

would receive discounted rates, because by granting the discounts all of their other customers will benefit from reduced costs.

Cost Reductions Resulting from Reduced IOU Capital Requirements

California needs substantial new generation and needs it very promptly. Exhibit 47. AB 57 and the Commission's procurement proceeding are largely driven by the IOUs contentions that investment in procurement is difficult and risky. In fact, it is clear that generation procurement has a higher risk (and therefore results in higher costs of debt and of equity) than distribution (the other large area of capital requirements for IOUs).

A number of potential community choice aggregators (such as CalCLERA) are actively seeking to develop new generation. The generation which they develop will directly reduce the capital requirements of IOU in the area which has the greatest cost of capital—generation.

Thus, as community choice aggregators reduce the procurement responsibility for IOUs, there are savings in the cost of capital, all of which would cost reductions either go to the IOUs shareholders or to IOUs bundled ratepayers.

Request for a Collaborative Process to Promptly Establish a Reasonable Credit

CalCLERA recommends and requests that if there is any disagreement on what, if any, level of credit is appropriate for community choice aggregators which develop new electric generating resources, that a collaborative process be promptly commenced to resolve the issue.

As explained above, not all the issues in this proceeding are "zero sum games." An appropriately designed credit will reduce the cost and improve the reliability of electricity for all California electric consumers.

There should be common interest in achieving such an objective. Moreover, determination of an appropriate credit does not require agreement on the base CRS, with its numerous and often contentious issues.

There are a variety of structures which could be used for a successful collaborative process and CalCLERA would be supportive of any of them. However, the most expeditious structure might be a settlement conference facilitated by an Administrative Law Judge.

Single Customer Status for CRS Exemptions

[IVDA] IVDA supports the proposal offered by The Utility Reform Network ("TURN") to treat a CCA like a single customer for purposes of qualifying for the customer generation CRS exemptions adopted in D.03-04-030.[137] IVDA also supports the clarification of TURN's proposal, as offered by TURN's witness Mike Florio during evidentiary hearings. In response to

[137] *See* Reply Testimony of Mike Florio for TURN, Exhibit 37, at 11-12.

a question from PG&E's counsel, Mr. Florio clarified that TURN's proposal would apply to a joint powers authority if the cities and/or counties forming that joint powers authority were contiguous and if the generation was located within the boundaries of the joint powers authority.[138]

[Local Power] Local Power supports TURN's proposed treatment of a CCA as a "single customer" under the Customer Generation Departing Load decision (D.03-04-030), making CCA's eligible for a CRS exemption under a 1500MW and 3000MW cap. Whereas under Direct Access customers selected service under an opt-in mechanism involving individual contracts, CCA customers select service under an opt-out mechanism involving a single common contract. (PUC 366.2c15).

Within that single contract, CCA's must comply with the Renewable Portfolio Standard, and large scale renewable generation facilities such as solar photovoltaics, fuel cells and other D.03-04-030 compliant resources will be among the available resources with which to comply with this legal requirement.

As participation in the purchase from all DG facilities will occur within a single contract, CCA creates the opportunity to "reduce transaction costs to consumers" (PUC 366.2c1) through the installation of large scale ultra-clean distributed generation that is favored by the Commission.

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[138] TURN/Florio Reporter's Transcript ("RT") 912.

Because these facilities are components of the CCA's contract portfolio, they are in fact acting as a single customer for purposes of the DG rules.

PG&E objects that the CCA "would be metering and charging the customer for energy delivered," (Id., p.32), but in fact the CCA is prohibited by AB117 from metering and charging the customer - tasks which the utility controls exclusively (PUC 366.2c9). The very fact that PG&E meters and bills these customers does not change the formation of the CCA as a single purchasing entity with universal access, equitable treatment of all ratepayers, and common terms and conditions. CCAs are a single customer and are entitled to the D.03-04-030 CRS exemptions.

13. Tiered CRS that Reflects Benefits

[Local Power] Potential benefits to all bundled service customers from CCA's implementing aggressive energy efficiency, conservation and generation programs include but are not limited to:

- Increased Reliability;
- Avoided new generation costs in the rate base;

- Avoided new transmission costs in the rate base;
- Avoided new distribution costs in the rate base.
- Reduced fuel charge costs and price volatility through reduced demand for gas-fired generation, on which California utility investor-owned utility ratepayers already depend for 36% of their power;
- Reduced wholesale power costs from reduced demand in the wholesale market which, all other things being equal, cause the price in the market in which IOUs purchase more than two thirds of their energy for resale to be reduced, whose effect in terms of dollars saved by IOUs bundled customers could be significant.

CalCLERA's witness, Dr. Cicchetti testified the Commission should consider distinguishing between CCA that build power plants, and CCA that simply go into the same pool of resources in the Western market to purchase power, and that a 50% credit would be justified based on the following analysis: assuming at IOU demand in California of 40,000 MW, and 250 million MWHs per year, as a result of reducing demand across the wholesale market, a price reduction of \$0.20 per MWH, or .02¢ per kWh wholesale costs for IOU would be reduced by \$55,000,000, or approximately 50% of the assumed base CRS. Stated another way, if the reduced demand on the system reduced wholesale market prices by 2/10's of a mill/kwh MWH, the savings across the entire system would justify the 50% credit to the CCA (CalClera Witness Cicchetti, .

AB117 directs the Commission to calculate a CRS based on a CCA's implementation plan, and specifies that the Commission may require a level of detail to be included in such plans so as to reasonably forecast and net out the costs and benefits that would be associated with the plan.

The categories of detail in a CCA implementation from which benefits may be estimated are outlined in AB117, which provides that a CCA establishing electrical load aggregation shall develop an implementation plan detailing *the process and consequences* of aggregation, and must contain an organizational structure of the program, its operations, and its funding; ratesetting and other costs to participants; provisions for disclosure and due process in setting rates and allocating costs among participants; the methods for entering and terminating agreements with other entities; the rights and responsibilities of program participants, including, but not limited to, consumer protection procedures, credit issues, and shutoff procedures; termination of the program; a description of the third parties that will be supplying electricity under the program, including, but not limited to, information about financial, technical, and operational capabilities.

Within 90 days after the CCA establishing load aggregation adopts and files its implementation plan with the Commission, the Commission shall certify that it has received the implementation plan, *including any additional information necessary to determine a cost-recovery mechanism*.

After certification of receipt of the implementation plan and any additional information requested, the commission shall then provide the CCA with its findings regarding any cost recovery that must be paid by customers of the community choice aggregator to prevent a shifting of costs as from DWR or utility procurement obligations (PUC Section 366.2©)7).

In order to assess the benefits of a CCA implementation plan, the Commission may thus request additional information about any element contained in a CCA's Implementation Plan.

In fact, San Francisco's adopted Community Choice ordinance (City an County of San Francisco Ordinance 86-04, Approved May 27, 2004) provides a good example.

While only an implementation ordinance and not an implementation plan, this ordinance requires that certain elements be included in a subsequent Implementation Plan to be completed in November, 2004 for adoption and submission to the Commission. Thus, the ordinance provides a basis on which the Commission may anticipate the generic level of detail it may require from a CCA's implementation plan in order to reasonably estimate and monetize its benefits to bundled service customers.

Thus, the ordinance provides a preliminary model with which to determine the level of detail needed in an implementation plan to reasonably identify, measure, monetize and credit such benefits against any gross costs attributable to customers participating in a CCA's load departure.

Specifically, the San Francisco ordinance orders that the Implementation Plan shall include a bidding requirement that Electric Service Providers (not the CCA) demonstrate insurance or post a bond to insure the costs of involuntary return of ratepayers to bundled service (Ordinance 86-04, Section 3(A)9(III), p.6). Second, the Plan must require qualifying ESP bids to include in the price of their bids the cost of a portfolio of resources that 107 Megawatts of load reduction through electricity load management and efficiency measures, 31 Megawatts of in-City solar energy, 72 Megawatts of new wind energy imports by 2012, as well as new natural gas-powered generation needed to close over 420 Megawatts of power generating facilities at Hunters Point and Portrero power stations (SF Ordinance 86-04, Section 3(A)9(II) on page 6 and Section 1(E) on page 5).

Thus, San Francisco's Implementation Plan will contain a great level of detail in terms of load reduction commitments, physical grid and procurement planning impacts – and thus reasonably predictable benefits to bundled service customers.

The CPUC has broad authority to request additional information necessary for it to calculate a CRS. Thus, if a CCA's implementation lacks certain details necessary for the Commission to monetize the benefits it would offer bundled service customers, the Commission may request such information prior to assignment of a CRS. This authority to include benefits provides the

Commission with a critical opportunity to forecast the actual planning impacts of CCA as they go through the implementation plan certification process.

Undertaking such a process will improve the Commission's forecasting accuracy and facilitate better gatekeeping between utility procurement and CCA load departures to minimize stranded costs and assets. Because a CRS netting benefits against gross costs is gauged to the specific and binding resource commitments made by a CCA in its plan should its load ultimately depart, the Commission's overall electric procurement planning certainty will be provided by the CCA's *a priori* bidding requirements. The only remaining uncertainty relative to Commission planning will be whether the CCA's Implementation Plan – once assigned a CRS by the Commission – actually results in an ESP contract – but the ultimate outcome will have been reduced to two possibilities rather than being.

Thus, a CRS reflecting net costs (gross costs minus net benefits) is not only required by AB117, but will also greatly assist the Commission in improving the accuracy of its forecasting and avoiding the creation of future stranded costs in its AB57/SB1976 New World Procurement authorizations to the electric utilities, as directed by the Governor (Exhibit 47, p.1).

[Local Power] **a. CRS EXEMPTION FOR ELECTRIC UTILITY PROCUREMENT IS NEEDED**

The exemption should be even broader. The principle proposed by Mr. Clarke of IDA. is that unforecasted load should be exempt from a CRS because DAR costs are not attributable to such load. Clearly, this principle should be applied in all instances. Whereas DAR obligations were incurred by a state agency acting to relieve Pacific Gas & Electric, Southern California Edison and San Diego Gas & Electric of their historic obligation to serve their customers (and thus also the regulatory compact itself) in the middle of a government crisis, New World utility procurement is a new process conducted pursuant to Assembly Bill 57 (Wright, 2002), which was signed by Governor Davis on September 24, 2002 - the same day he signed AB117. AB117 itself is very clear that CRS obligations associated with utility procurement shall be limited to *costs associated with a particular customer*. 366.2 (f) provides that a retail end-use customer purchasing electricity from a CCA shall reimburse the utility that previously served the customer for (1) " The electrical corporation's unrecovered past under collections for electricity purchases, including any financing costs, *attributable to that customer*, that the commission lawfully determines may be recovered in rates" and (2) "Any additional costs of the electrical corporation recoverable in commission-approved rates, equal to the share of the electrical corporation's estimated net unavoidable electricity purchase contract costs *attributable to the customer*, as determined by the commission, for the period commencing with the customer's purchases of electricity from the community choice aggregator, through the expiration of all then existing electricity purchase contracts entered into by the electrical corporation." Thus, the utility CRS to be imposed on CCA customers for both under-collection and New World Procurement are statutorily limited to costs associated with each customer, and must have been avoidable - meaning costs associated with over-procurement by utilities are not recoverable from CCA customers.

b. <u>A CCA CRS EXEMPTION IS NEEDED TO PROTECT AGAINST CONFLICT OF INTEREST BY UTILITIES CONSIDERING CCAS AS THEIR COMPETITORS</u>

Witnesses from PG&E, Edison and SDG&E have each indicated that they consider CCAs to be their "competitors." In particular, PG&E witness Sandra Burns indicated that "while PG&E does not necessarily view CCAs as competitors in an adversarial sense, PG&E does recognize that there may be healthy competition in seeking to reduce customer cost," and classes them as "Market Participants" alongside Electric Service Providers and other sellers of power. SDG&E and Edison's witnesses have made similar statements, ignoring AB117's *assertion that "Customers shall be entitled to aggregate their electric loads as members* of their local community with community choice aggregators (emphasis added, PUC 366.2. (a) (1)), and also that "(n)otwithstanding Section 366, a community choice aggregator is hereby authorized to aggregate the electrical load of interested electricity consumers within its boundaries *to reduce transaction costs to consumers, provide consumer protections, and leverage the negotiation of contracts*." (Emphasis added, PUC 366.2 (c))(1)). This presents a serious legal conflict for the utilities, because the officers of PG&E, Edison and SDG&E have a fiduciary responsibility to their shareholders to maximize their return on investment. If the utilities view CCAs as competitors, the utilities have an incentive to over-procure in order to deliberately create stranded costs and an increased CCA CRS, in order to prevent CCA load departures. Yet AB117 requires that "(a)ll electrical corporations shall *cooperate fully* with any community choice aggregators that investigate, pursue, or implement community choice aggregation programs" (PUC 366.2(c)(9). As the utilities have said they view CCAs as competitors, they put themselves in the position of violating their fiduciary responsibility to their customers, or violating the law. As AB57 authorizes procurement without Commission review of contracts, a dangerous situation could face the commission unless it establishes mechanisms with which to prevent over-procurement. With the potential advent of shareholder incentives, this problem becomes deeper. Thus a CCA CRS exemption is not only appropriate but needed.

c. A CCA CRS EXEMPTION FROM COSTS ASSOCIATED WITH UTILITY OVER-PROCUREMENT WOULD NOT VIOLATE THE COST-SHIFTING PROVISIONS OF AB117

While AB117 has provisions that express the principle of avoiding cost-shifting from CCA customers to bundled service customers, it clearly does not intend for this principle to be applied according to a gross cost, but rather a net cost, definition, as it is in all CPUC ratemaking proceedings. For example, while 366.2(a) 17 provides that "(a)n electrical corporation shall recover from the community choice aggregator any costs reasonably attributable to the community choice aggregator, as determined by the commission, of implementing this section, including, but not limited to, all business and information system changes, except for transaction-based costs as described in this paragraph," it also indicates that "*(a)ny costs not reasonably attributable to a community choice aggregator shall be recovered from ratepayers*, as determined by the commission. Thus, AB117's principle of avoiding cost-shifting does not mean that bundled service customers should not bear any of the costs associated with CCA in general, and may not be used simply to charge a CCA wherever there is a cost associated with CCA's in general.

d. A CCA CRS EXEMPTION FROM CERTAIN KINDS OF ELECTRIC UTILITY PROCUREMENT WOULD NOT BE BARRED BECAUSE OF THE "INDIFFERENCE PRINCIPLE" FROM DIRECT ACCESS

The principle of indifference does not govern CCA and should be modified to reflect changes introduced by AB117. First, because AB117 section 366.2(a)(3)(b) provides that "If a public agency seeks to serve as a community choice aggregator, it shall offer the opportunity to purchase electricity to all residential customers within its jurisdiction," and section 366.2(c)(4)(A) requires that CCA implementation plans include provisions for "universal access," CCA customers are statutorily required to include all bundled service customers in a CCA jurisdiction who do not opt-out of the CCA program. Unlike Direct Access, under which cherry picking of customers with optimal loads was allowed and widely practiced, CCA's are subject to universal service requirements, thus CCA customers are by definition indistinguishable from bundled service customers, and are entitled to the same protection against cost shifting from utility over-procurement that bundled services customers deserve. Second, because Section 366.2(c)(9) provides that "(e)lectrical corporations shall continue to provide all metering, billing, collection, and customer service to retail customers that participate in community choice aggregation programs," CCA customers, unlike DA customers, are statutorily required to remain utility customers for all utility services, and as such are entitled to the same protection against cost shifting from utility over-procurement that is enjoyed by bundled service customers.

e. CCA CRS EXEMPTIONS ON COSTS ASSOCIATED WITH UTILITY PROCUREMENT AUTHORIZED AFTER A CCA HAS APPROVED AN ORDINANCE

PURSUANT TO AB117 WOULD NOT CAUSE COST SHIFTING AS DEFINED IN AB117

As indicated above, AB117 specifically limits CCA CRS obligations for utility procurement to contract costs that are "equal to the share of the electrical corporation's estimated net unavoidable electricity purchase contract costs attributable to the customer," (PUC 366.2(f)(1) and 366.2(f)(2)). Thus AB117's definition of "cost shifting" relative to CCA CRS is the same as it is relative to implementation or transaction costs, but in the case of the CCA must be a number ("equal to") and must be attributable to the customer herself.

As I have repeatedly cited, AB117 provides that costs associated with CCA in general that are not reasonably attributable to a particular CCA "shall be recovered from ratepayers, as determined by the commission." (PUC 366.2(c)(17)). Thus, bundled service customers may pay for costs associated with CCA in general - that is, costs which are inherent to having CCA as a permanent recourse to bundled service customers under California law. Because AB117 requires that every CCA to prepare and pass an ordinance to implement CCA, to prepare and file a detailed implementation plan with the Commission and wait 90 days to receive certification and a CRS from the Commission ((366.2(c)(3)), then undertake a 120 day opt-out period for notification of customers and opt-out prior to the actual transfer of customers, the utility procurement costs and risks associated with this time lag are not attributable to the CCA's customers, but are, rather, inherent costs associated with CCA in general. Accordingly, these costs should be born by all bundled service *customers*, who under AB117 have an interest in maintaining their "entitlement" to aggregate (PUC 366.2(a)) and depart utility procurement - and in this sense will benefit from the availability of CCA as a permanent recourse to high electric utility rates that may be incurred by electric utilities pursuant to AB57. Given that it is AB57, not any historical "regulatory compact" or "obligation to serve" (both of which were abrogated by the utilities when the state assumed their obligation to serve California ratepayers at great expense in 2001) that now authorizes utility procurement, it is clearly in the interests of ratepayers to have this recourse, and logical that they would bear the costs of maintaining Community Choice in order to keep it available to them. Considering that CPUC Decision 04-01-050 on January 22, 2004 also formally eliminated Commission review of electric utility procurement contracts, replacing it with a surrogate "procurement review committee," the diluted regulatory authority of the Commission over electric utility procurement may not provide adequate protection for residents, emphasizing the fact that bundled service ratepayers need Community Choice as a permanent option, and should bear any CCA-related costs that are not attributable to a specific CCA or to a specific customer. In particular, the incremental added cost associated with an electric utility entering into short-term contracts in order to make room for a CCA which has provided notice, and at minimum for 5-10% of it customer load to depart each year, should be born by bundled service customers - the cost of having CCA as a recourse.

f. BENEFITS TO BUNDLED SERVICE CUSTOMERS SHOULD BE INCLUDED IN A CRS CREDIT ESTABLISHED ACCORDING TO THE INFORMATION REQUIRED BY THE COMMISSION IN A CCA'S IMPLEMENTATION PLAN

As I indicated in my opening testimony, the current crop of CCA's now spending funds on implementation have set a goal of a minimum 40% Renewable Portfolio Standard. Whereas the 20% RPS law will result in an 8% increase under California's current statewide average of 12% renewable in the mix, the CCA cities'40% RPS will result in a 28% increase. Clearly, this will have a significant beneficial impact on bundled service customers in the form of freeing up thousands of Megawatts of transmission capacity for use by bundled service customers, eliminating the need for new transmission to meet regional growth, eliminating the need for substation and line upgrades, and decreasing the likelihood of blackouts for bundled service customers. A more specific example is illustrative. The City and County of San Francisco has already indicated in its recently adopted CCA ordinance that it will not accept bids that do not include 360 Megawatts of new wind, solar, energy efficiency and conservation measures for a customer base that ranges from 650 Megawatts to 850 Megawatts of load. With a minimum of 211 Megawatts of this being installed on the distribution side of PG&E's substations, this CCA will make at least 211 Megawatts of transmission capacity available to bundled service customers in the South Peninsula that are served by the same PG&E transmission line. These sorts of benefits are tangible and should receive a commensurate CRS credit.

14. Assumption of Liability for "In-Kind" MWhs

Consistent with the net cost definition of costs described above, nothing restricts the ability of CCA to voluntarily negotiate buy out utility or DWR contract obligations.

15. Payment of Bond Charge by New Customers

DWR bond charges are defined by AB117 as a charge equivalent to the charges that would otherwise be imposed on the customer by the commission to recover bond related costs had a CCA never formed (PUC Section 366.2(e)1). New Customers should be required to pay any bond charges that a new CCA customer would have paid moving to California as a bundled service customer, whether from within the state or without.

[LACV] In establishing a CCA CRS, the Commission must determine which portions of the current CRS may be applicable to CCA customers. As explained by DWR, the CRS currently contains four components: (1) DWR contract costs, (2) bond costs associated with DWR.contract responsibility, (3) past utility procurement under-collections, and (4) CTC. [Ex. 1, Attachment at 5.]

Under the established CRS, every customer, even those who may be new customers in previously unserved territory within a municipal utility service territory, are held responsible for the bond costs. Under the CCA program, customers will be customers of both the CCA and the utility regulated by this Commission. Thus, all customers served, whether they be new or old, will be served by both the utility subject to this Commission’s jurisdiction, and the CCA. Thus, the

County and City believe that the bond charge should have universal applicability. However, this universal applicability of the bond charges to CCA customers does not assume responsibility for any other component of the CCA CRS, with the possible exception of the CTC charge under AB1890.

16. Unbundling of CRS on All Customers' Bills

[Local Power] While utility witnesses have claimed that they see no reason to unbundle the CRS on all customers' bills, it is clear that this would facilitate a clear comparison of the terms of bundled utility service with a CCA's chosen ESP's service. If the utilities wish for consumers to be well informed of their choices, unbundling of the CRS is a basic, low cost measure.

[LACV] Mr. Monsen, on behalf of the LGCC, testified persuasively for the unbundling of CRS on all utility customer bills. [Ex. 28, 29.] The County and City do not believe it is necessary to repeat the many persuasive reasons described by Mr. Monsen as to why this is an equitable solution, if not the only solution. However, the County and City wish to add that the only way to reconcile a wide variety of issues in this proceeding is to create such separate unbundling.

The CRS charge will now have at least four separate calculations; direct access, distributed generation, municipal departing load, and CCA. Thus, a large number of customers within the state will be paying one form or another of CRS. The basis of the CRS is the indifference of the remaining customers. Thus, all customers of utilities, and even customers of new municipal utility service, would be responsible for certain charges. It is important that these charges are clear and equitable.

Another way of creating equity in this regard is to allow the CRS as with the "bottoms up" calculations of direct access service rates, to be separately stated on all bills..Further, any new world generation component of a CCA CRS is not applicable to the CRS with regard to the other three categories of customers who will pay a CRS charge. It is most nearly applicable to, potentially, a portion of the generation component of the utility service to its existing bundled customers. Again, unbundling is the only way of adequately stating such rates.

Finally, charges for services to CCA customers as compared to services rendered for direct access or bundled customers need to equitably stated and charged. The only way to establish any non-discriminatory treatment among customer classes is to have such rates, and terms and conditions of service, separately stated and applicable equally to whether such customer is bundled, direct access, or community choice aggregation. As an example, utilities are proposing a methodology by which they charge the full distribution rate to CCA customers, assess additional charges for CCA service, and then make some credit back to CCA customers having reflected that they have paid for these costs already within the distribution component. A simpler solution may be to separately state billing, metering and other services as they relate to all customers and have all customers pay such rates only once. This may merely require the separate stating of such costs within bundled service tariff sheets, but be rolled into the total calculation within the line items in the customer bill itself.

[LGCC] As discussed in other sections of this Brief, the Commission's task is not to force CCA into the direct access model, but rather to facilitate the implementation of a unique program using the direct access model where there is evidence in the record that the particular rule or mechanism is appropriate. The IOUs seem to believe that the intervenors bear the burden of proof to show that the direct access model should not apply, rather than having to submit evidence that any particular rule should apply. The Commission should not take such a narrow view of its obligations.

The DA-in/DA-out methodology was created in response to a unique set of facts: in August 2001, the Commission was considering imposing a retroactive suspension of direct access as of July 1 in response to a significant increase in the levels of direct access during that summer. The Commission was concerned that these customers were taking unfair advantage of the Commission's delay in suspending direct access by leaving IOU service for the purpose of avoiding the DWR charges, and thereby stranding these costs.[139] Rather than create a constitutional problem by retroactively voiding private contracts, in Decision 02-03-055 the

[139] D.01-09-060, at 5-8.

Commission decided to adopt a September 20, 2001 suspension date with the proviso that IOU customers be indifferent as between a July 1, 2001 and September 20, 2001 suspension date. The DA-in/DA-out methodology was developed in order to measure the difference in DA load between these two dates.[140] This method of measuring "indifference" does not make sense outside that context.

The Commission should indeed learn from the lessons of the direct access CRS and take this opportunity to craft a better approach. While it might seem easier to adopt the DA-in/DA-out methodology, in fact this methodology is complex and unwieldy[141] and is a mystery to all except a lucky few at Navigant, DWR, and the IOUs. In the interest of simplicity, transparency, and equity, the Commission should order the IOUs to unbundle all charges and to build the CCA CRS from the bottom up.[142]

This approach is not novel. This is in fact how rates are normally set. The Commission has directed both SCE and PG&E to use the so-called bottoms up billing for direct access customers.[143] Separately, in February of this year, the Commission directed PG&E to show specific charges for CTC, Regulatory Asset, the DWR bond charge, and the DWR power charge separately on Direct Access customers' bills and the CTC, Regulatory Asset, and the DWR bond charge separately on bundled customers' bills.[144] PG&E supports unbundling the Bond Charge

[140] D.02-11-022, at 18-20.
[141] Exh. 28, at 43.
[142] Exh. 28, at 44-45; Exh. 29, at 23-25.
[143] D.03-08-061, Ordering Paragraph 1 (A.98-07-003, PX Credit proceeding)
[144] D.04-02-062, Ordering Paragraph 9 (I.02-04-026, Pacific Gas & Electric's bankruptcy proceeding)

and the Regulatory Asset Charge, and states that unbundled could simplify the CRS calculation.[145] This approach of unbundling charges should apply to the CRS charges for IOU and CCA customers.

Unbundling the CRS charges also makes sense because the amount of each charge will be the same regardless of whether the customer is an IOU customer or a CCA customer. There is no justification for imposing different rules for similarly situated customers.

The unbundled CRS components would consist of the DWR bond charge, DWR above-market power costs, on-going CTC, and, for PG&E, the Regulatory Asset. The level of the unbundled components should be the same for "like-situated" customers whether bundled or CCA. The customer, whether bundled or CCA, served on the same utility rate schedule, would pay the same amounts for these cost components. Pursuant to CPUC decisions, much of the unbundling has already been done.

Unbundling has many benefits: it is simple to administer and does not require on-going proceedings for true-up and reassessment outside of the normal rate setting process; the IOUs would be assured of collecting the correct amount for the DWR power charge, DWR bond charge, CTC, and Regulatory Asset from CCA customers and bundled customers alike; and IOU and CCA customers would be able to make informed decisions about the choice of provider by

[145] Exh. 12, at 3-7.

making an apples-to-apples comparison of rates. Finally, this methodology will ensure that the CRS complies with the AB 117 mandate that each customer bear its fair share of DWR costs.

17. Under or Overcollection of Utility Costs

Under or overcollection of utility costs should be regarded as a cost inherent to having CCA that is not attributable to a particular CCA or CCA customer, and must therefore be paid by (or credited to) all ratepayers.

[LACV] The County and City believe that the CCA CRS should be limited to remaining, actual, stranded (or excess) DWR costs and bond charges. Thus, no under or over collection of such CRS by the utility is possible outside of the context of the true up mechanism associated with the current CRS for direct access.

18. Treatment of Forecasting Errors

[Local Power] Forecasting errors that are attributable to a CCA or its customers should be paid by the CCA or its customers, provided that the utility has made all data available to a CCA seeking to plan its loads once it is formed by ordinance.

Forecasting errors not attributable to a CCA or its customers should be paid by all ratepayers or by utility shareholders, whether considered fixed or incremental costs consistent with PUC Section 366.2(f) or as a procurement cost pursuant to PUC Section 366.2(c)17.

CCA denied access to any customer-specific or interval meter data by its utility prior to completion of their Implementation Plan, should be exempt from any related charges. A failure of the utility to cooperate in providing this data places a disproportionate burden on utility shareholders to pay for the cost of any forecasting errors made blindly as a result of the utility's failure to cooperate fully with the CCA, including provision of billing and electrical load data, including, but not limited to, data detailing electricity needs and patterns of usage, as determined by the commission, and in accordance with procedures established by the commission (PUC Section 366.2(c)9).

[LACV] The County and City believe this is not a true issue. The current DA CRS is subject to a true up mechanism. The CCA CRS is also suggested to be subject to a true up mechanism..Therefore, if any load forecasting results in an over payment of CCA CRS, or an underpayment of CCA CRS, it will be adjusted within the true up mechanism.

19. Proposed CRS Exemptions for Baseline Residential Customers

[LACV] The Commission has asked whether the existing 130% baseline exemption applicable to residential customers as a result of AB1X, should be made applicable to CCA service. While there has been significant discussion of the merits of this issue, the issue really involves the extent of the Commission's jurisdiction and the scope of AB1X.

It is the position of the County and City that AB1X is applicable only to the commodity component of utility service. As CCA service will replace the commodity component of bundled service, AB1X is by definition inapplicable. The County and City believe that for various policy reasons, a CCA may wish to utilize the treatment provided by AB1X for its residential customers. However, the County and City believe that such a decision is up to the CCA in its individual role as ratemaker for services to its customers. The same way that energy service providers are not required to mimic the treatment to direct access customers of the commodity component of rates charged to utility service customers, CCAs should not be held to specific rules applicable to utility customers under rates set by this Commission. Further, as CCAs are governmental entities with specific legislative and statutory responsibilities and rights, any determination by this Commission of rates to be established by the CCA to any customer class, runs afoul of the Commission's limited jurisdiction in this regard.

[CCSF] The CRS should be a uniform cents/kWh across all CCA customers within a utilities service territory (subject to vintaging considerations). CCAs can address differences in residential rates due to AB1X restrictions by CCA rate design of generation rates. Both PG&E and SCE in opening testimony argued that the prohibition regarding rate increases for residential customer usage up to 130% of baseline should not apply to CCA customers.[146] There are currently residential direct access customers who do not receive an exemption from the CRS and there is no provision in AB 117 for such special treatment of CCA residential customers.[147] However, CCSF believes that CCA customers deserve the same cost protection as mandated by AB1X. CCAs can deal with the differential between residential tiered rates by CCA rate design of generation rates to ensure a competitive service for such customers.[148] To follow the PG&E alternative proposal of tiered CRS rates depending upon utility rate schedule will result in a varying average CRS rate depending upon the customer composition within different cities. The PG&E alternative rate design proposal would create a different CRS for each CCA, depending on the CCA's mix of different rate classes.[149] This would effectively be cost-shifting amongst CCA communities which is also prohibited by AB117[150] and would also create "multiple CRSs for different kinds of customers."[151]

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146 Exhibit 26 at 14.
147 Id.
148 Id. at 15.
149 RT at 706.
150 Exhibit 26 at 16.
151 RT at 717.

20. Proposed Exemption for Customer Generation

This subject is addressed under III, 13 above. Customer generation provides a benefit to bundled service customers that should be reflected in the CRS based on commitments contained in a CCA's implementation plan.

21. Proposed Exemption for New Generation

This subject is addressed in section 12 and 13 above.

22. Proposed Exemption for Norton Air Force Base

[Local Power] AB117 specifically requires that CRS for DWR and utility contracts be limited to actual costs that are attributable to the actual customers who are being charged through their CCA. While 366.2(d) (1) indicates that "It is further the intent of the Legislature to prevent any shifting of recoverable costs between customers" for Department of Water Resources contracts, it also indicates that CCA customers "should bear a *fair share* of (DWR) electricity purchase contracts." 366.2(e)(1) indicates that CCA customers should pay "A charge equivalent to the charges that would otherwise be imposed on the customer by the commission to recover bond related costs" meaning the fair share of bond charges is what they would otherwise have paid had they not participated in a CCA. Finally, 366.2(e)(2) provides that a CCA customer should pay for "(a)ny additional costs of the Department of Water Resources, equal to the customer's proportionate share of the Department of Water Resources' estimated net unavoidable electricity purchase contract costs as determined by the commission, for the period commencing with the customer's purchases of electricity from the community choice aggregator, through the expiration of all then existing electricity purchase contracts entered into by the Department of Water Resources." Because the load at Norton base was not included in the DWR's forecasts, the DWR did not enter into power electricity purchase contracts on behalf of loads associated with Norton, and incurred neither bond charges nor other costs related to these customers. Therefore, the load at Norton should be exempt from the DWR component of the CRS.

[LACV] This issue is not related exclusively to Norton Air Force Base. The request of IVDA relates to the exemption from CCA CRS for new load on existing military bases that are served.under a CCA program. The argument provided by the proponents [Ex. 43] is that DWR did not purchase power in the anticipation of serving new customer load on converted military bases.

The County and City support the argument of the IVDA in concept for two reasons. First, the CCA CRS will likely have only two components: DWR contract costs and DWR bond costs. In both instances, it appears that DWR did not contract for power with the assumption of serving utility load within such areas. Thus, the Commission's consistent position with respect to CRS responsibility relates to whether DWR purchase power with regard to these customers. If the answer is no, then there should be no responsibility as well.

Second, the only potentially new component of the CCA CRS is “new world” power costs; that is, contract or facility construction commitments by utilities to serve a load which later becomes a CCA load. Under those circumstances, utilities should not be planning to purchase power to serve undeveloped areas subject to governmental jurisdiction in which no current proposal has been accepted for the provision of service by any party, no matter a utility. Thus, the potential new component to a CCA CRS also appears to be inapplicable.

To the extent to which any of the assumptions above are incorrect, the County and City believe that the issues associated with military base conversion load responsibility for CCA CRS may be revisited. However, under the facts described above, it appears that the Commission’s consistent policy would exempt such load from CCA CRS.

[CalCLERA] Proposed Exemption for Norton Air Force Base

In this section IVDA addresses its proposal to have the CPUC authorize a limited exemption of CRS for load at the former Norton Air Force Base (“Norton”) within the IVDA jurisdictional boundaries. The record evidence in this proceeding demonstrates that SCE specifically calculated and forecast loss of load due to military base closures, which includes loss of load at Norton. The IVDA argument is no more complicated than suggesting that the fair share principle mandates a

CRS exemption for any load reduction forecast for "military base closings" that were provided to DWR before the bulk of DWR's power purchases. The fair share principle from CPUC decisions supports granting CRS exemptions to load, associated with military base closings, that were not included in DWR's forecast

The fair share principle imposes CRS on a customer when it is determined that DWR incurred costs on behalf of that customer. As shown below, the load associated with military base closings was not included in the forecasts relied upon by DWR. Accordingly, the fair share principle militates against the imposition of CRS on this load – load that DWR did not anticipate serving, and did not incur costs for. Also as shown below, the CPUC may rely upon record evidence in this proceeding to provide the criteria and basis for determining that a certain amount of load associated with military base closings was not included in DWR's load forecast when DWR made its power purchases.Evidence in the record demonstrates that SCE provided forecasts to DWR that included specific reductions for load associated with military base closings

IVDA acknowledges the testimony by SCE and DWR witnesses stating that DWR did not specifically reduce any load for "CCA." IVDA, however, has not specifically requested an exemption for load reductions that were forecast specifically as "CCA." IVDA proposes an exemption for a particular customer group the load of which was not included in forecasts relied upon by DWR in making its power purchases.[152] And, the record shows that the relevant

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[152] While DWR acknowledged that it did not reduce its load forecast specifically on account of CCA, it also acknowledged that individual utilities could have explicitly reduced their respective load forecast to account for a particular customer group. *See* DWR/McMahon

customer group is categorized as load associated with "military base closures."[153] IVDA presents its proposal in this proceeding because, in essence, AB 117 has ripened the issue for CRS on military base load by authorizing cities and counties to consider serving this load as community choice aggregators.

Load forecasts provided by SCE to DWR in July 2000 were derived from the SCE Sales Forecast included in the record of this proceeding.[154] In this Sales Forecast, there is a column listing specific monthly "load lost due to military base closings" with listed load loss values typically around 25,000 MWh per month for the years 2001 and 2002.[155] SCE's response to IVDA's data request stated that the forecast "assumed that MWh sales to Norton would decline . . . in 1998 and 1999 and stay at that level through the forecast period."[156] However, this is countered by SCE witness Jazayeri who testified that SCE had included a "limited amount of load loss to the closure of Norton in the forecast."[157] The SCE Sales Forecast also demonstrated SCE's contemporaneous

RT 47,48 ("Q: [Y]ou stated that it is DWR's view that it, that is, DWR, did not modify its forecast to include community aggregation; is that accurate? A: Yes. Q: In your view, Mr. McMahon, is it possible however, that the individual utilities, that is, not DWR, could have assumed factors in their own respective load forecasts that resulted in a reduction of forecasted load for a particular customer group? A: Yes.").

153 *See* SCE 2002 GRC Workpapers, Exhibit 43, Attachment 1 at 36-42.

154 *See* SCE 2002 GRC Workpapers, Exhibit 43, Attachment 1; Data Request Set IVDA-01, Exhibit 52, Response 1.0.

155 *See* SCE 2002 GRC Workpapers, Exhibit 43, Attachment 1 at 41-42; Data Request Set IVDA-01, Exhibit 52, Response 3.1, 5.0.

156 *See* Data Request Set IVDA-01, Exhibit 52, Response 5.1; Additional Reply Testimony of SCE, Exhibit 51, at 2.

157 *See* Additional Reply Testimony of SCE, Exhibit 51, at 2. *See also* SCE/Jazayeri RT 186 ("Q: Did [the forecast from SCE to DWR] reflect any reduction in load associated with other customer groups, for example, specifically customer generation or cogeneration? A: Yes. We generally -- in our sales forecast, we first do a baseline sales forecast. And then we consider, for example, based on economic indicators, whether there's going to be a recession. We know something about the load in our service territory. You know, in your motion, you point to the -- to closure of military bases. I think, you know, our people forecast that. We look at the self-generation. We forecast that. And those are all reflected in our sales forecast.").

belief that “[s]ome further reduction in military presence in our service territory is expected.”[158] The record shows that SCE adjusted the Sales Forecast accordingly.

IVDA also acknowledges SCE’s statement that “[n]o specific monthly forecast was made by military base.”[159] The ultimate fact, however, is that the record in this proceeding includes testimony and documentation demonstrating that specific load loss forecasts for military base closings were used by SCE to prepare its forecast on which DWR relied in making its power purchases. Therefore, it is logical and reasonable for the CPUC to conclude that DWR did not incur costs to purchase power for a certain amount of this explicitly identified load category. **It is reasonable and consistent with Legislative intent and the CPUC’s CGDL decision to provide an exemption for load associated with military base closings**

In the CPUC’s CGDL decision, a CRS exception was granted for 3000 MW of customer generation departing load. The CPUC granted these exceptions to certain portions of the CRS and found that they “will not result in any cost-shifting among customers, since costs for those MW were not incurred by DWR.”[160] This no-cost-shifting analysis is directly applicable to load associated with military base closings since, as shown above, specific load losses were explicitly forecast by SCE and provided to DWR.

Additionally, in exercising its discretion in making its fair share determination for CGDL, the CPUC used certain policy justifications to provide greater exceptions to particular types of

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[158] *See* SCE 2002 GRC Workpapers, Exhibit 43, Attachment 1 at 13-14.

[159] *See* Data Request Set IVDA-01, Exhibit 52, Response 5.1.

[160] D.03-04-030, at 61, Finding of Fact 20.

customer generation.[161] The CPUC "harmonized" AB 117 with the legislative objectives of several other laws enacted to address California's energy woes and to "produce economic and environmental benefits."[162] By virtue of being a redevelopment agency established pursuant to the California Community Redevelopment Law,[163] the legislative objective for IVDA presents substantially similar policy objectives.

The specifically stated legislative intent for a redevelopment agency is to "[p]rovide a means of mitigating the economic and social degradation that is faced by communities the jurisdictions of which include military bases that have been ordered to be closed or realigned by the federal Base Closure Commission."[164] Furthermore, "[t]he Legislature finds and declares that extraordinary measures must be taken to mitigate the effects" of military base closures.[165] IVDA territory includes the former Norton Air Force Base, which was closed by the Base Closure Commission. IVDA asserts that its beneficial objectives as a redevelopment agency and the Legislature's call for extraordinary measures provide a strong basis for the CPUC to exercise its discretion to provide CRS exceptions to IVDA and similarly situated redevelopment agencies.

Lastly, IVDA points out that one-half of the 3000 MW CGDL exception was authorized for virtually any type of customer generation, and not just renewable generation.[166] This "other"

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161 This involved different variations of exceptions from DWR bond charges, DWR power charges, and CTC tail charges.

162 D.03-04-030, at 39-40.

163 Health & Safety Code §§ 33000, *et seq*.

164 Health & Safety Code § 33492(a).

165 Health & Safety Code § 33492.1.

166 D.03-04-030, at 51.

category of CGDL did not rise to the same level of policy justification as stated above, so the CPUC only exempted it from paying the DWR power charge.[167] At the very least, load associated with military base closings should be treated no less favorably. IVDA believes that it would be irrational and unlawfully discriminatory for the CPUC to exempt "other" CGDL from DWR ongoing costs, on the one hand, and to charge full CRS to load associated with military base closings, on the other hand.[168]

CPUC reasoning used to deny exemptions to MDL is not applicable to load associated with military base closings

In the MDL decision, the CPUC states that MDL should bear its fair share - concluding that MDL customers should be held responsible for DWR power costs because the CPUC found "no evidence of any explicit level of MDL the IOUs expected or that it was ever included in DWR's load forecast."[169] In the case of military base closings, however, SCE's witnesses *do* testify to specifically reducing SCE's forecast to account for the closings.[170] IVDA *does* offer evidence of specific adjustments.[171] Reductions for military base closings are *explicit* in the load forecasts. There *is* a record in this proceeding of specific load adjustment. As a result, there *is* a basis to adopt a specific exemption for load associated with military base closings.

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167 *Id.*

168 *See* Griffin v. Superior Court, 96 Cal.App.4th 757, 775 (2002) (stating that the equal protection clause requires the law to treat those similarly situated equally unless disparate treatment is justified) *as cited by* D.03-08-076, at 31. *See generally* U.S. Steel v. PUC, 29 Cal.3d 603 (1981).

169 D.03-07-028, at 36-37.

170 *See* Data Request Set IVDA-01, Exhibit 52; SCE/Jazayeri RT 186.

171 *See* SCE 2002 GRC Workpapers, Exhibit 43, Attachment 1; Data Request Set IVDA-01, Exhibit 52.

In the MDL decision the CPUC determined that PG&E's forecast was not relevant because it wasn't provided to DWR until after DWR had made the bulk of its purchases. Therefore, the PG&E forecast could not be used to establish that DWR specifically excluded load for MDL from its purchases.[172] In this proceeding, however, the record evidence demonstrates that SCE's forecast showing load reductions for military base closures was provided in time and was relied upon by DWR.

In the MDL decision, the CPUC also offered its policy reason for not exempting MDL, i.e., the possibility that "a specific DWR exclusion applied to MDL could create a price disparity between the IOUs and municipal utilities that could significantly accelerate the rate of municipalization."[173] This same logic cannot reasonably be applied to redevelopment agencies. The CPUC has no reason to fear, nor should it inhibit, an accelerating rate of redevelopment in accordance with the California Community Redevelopment Law. The law promotes and encourages redevelopment on closed military bases. It incorporates strong components for the health, safety and economic well-being of citizens in all surrounding communities. IVDA, as aredevelopment agency, is charged with this task and is subject to the local control of customers in surrounding areas. Lastly, IVDA is not suggesting that Norton alone deserves a shot at CRS exemptions for load associated with military base closures. Certainly, IVDA is arguing for itself, but it has not argued to the exclusion of other redevelopment agencies. The global nature of

172 D.03-08-076, at 12.
173 D.03-07-028, at 38.

IVDA's CRS exemption proposal is that forecasted load loss due to military base closures warrants consideration for this exemption. New load at Norton is not at issue here

In light of pending legislation[174] and the rehearing for NML, IVDA offers no comments on CRS for "new load" on a military base except to say that new load on a military base served by IVDA as a CCA should be treated no less generously than NML.

For the reasons stated and supported herein, IVDA requests that the CPUC conclude that CRS are not applicable to load associated with military base closings. In accordance with AB 117 and CPUC decisions, this exempted load should be no less than the amount of load reductions included in the IOU forecast used by DWR to purchase power. At the very least, it is reasonable and consistent with AB 117 to adopt an exception so that load associated with military base closings is not required to pay DWR ongoing power costs.

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174 ASSEMBLY BILL 426, amended in Senate *(June 14, 2004). This bill would prohibit the CPUC from imposing any CRS on a customer of a local publicly owned electric utility when the customer's service location has not previously received service from an IOU.*

VI. ESTIMATES OF INFORMATION FEES

The "Confirmation Letter" (SDG&E Fee#15) Fee of $0.47 per account discussed by SDG&E's witness is a good example of a fee which blatantly violates PUC Section 366.2(c)17 in that it is not attributable to a CCA or its customer, but is undertaken by a utility without any legislative basis simply as a policy of the utility.

SDG&E's witness admitted that the Confirmation Letter is separate from the four notifications required by AB117 (SDG&E Witness Dawn Osborne, June 9, 2004 Evidentiary Hearing, p.655, line 26), claimed that it was undertaken under Direct Access, but admitted DA customers do not pay for it(656, lines 11-14). Yet she indicated that this was the basis for the charge, indicating that "(I) there's an activity that we feel is essential that is directly attributable to the CCA program, yes, then I feel that cost should be recovered not from all ratepayers, but from the CCA." (SDG&E Witness Dawn Osborne, Page 661, lines 18-21.).

However, AB117 limits utilities charges to costs that are attributable to the CCA customer, and cannot therefore include costs that are neither mandated by AB117 nor requested by the CCA or CCA customer. Any other policy would invite utility abuse. It is clearly illegal to allow utilities to imposes charges for any activity they "feel is essential that is directly attributable to the CCA program," when the very fact the utilities are "feeling" it makes it attributable only to them alone.

While the CCA customer remains a captive customer of the utility for distribution, billing and metering, this does not make any communication to that customer a CCA-specific cost. If utilities choose to send out such letters, the cost must therefore be borne by all ratepayers or shareholders.

[LACV] As discussed above, during the cross-examination of Ms. Keilani [Tr. 94], information requested by the CCA community was described and categorized. Appendix B, which is called an "Information Item List," provides categories of information ranging from aggregate annual usage by customer class through to aggregate annual usage by rate schedule. Each of the individual utilities provided their estimate as to how difficult or expensive it would be to provide the information. "Free" is used to describe all information defined in Attachment C of Decision.34.

D.03-07-034; that is the information the Commission has already directed the utilities to provide. Other information fell into the category of "easy," defined as able to obtain and provide in less than four hours, or "moderate," able to obtain and provide between four and eight hours. Nothing on Appendix B was listed as either "difficult" or "extremely difficult" but several items were listed as "N/A," which meant that the utilities did not have the information or were not able to provide because of other issues identified in the Joint Report. *(See* Section (II)(F) above.) Within this category of information was load shapes and individual load research by sample CCA, energy efficiency information, and customer specific information. Load profiles and customer specific information are discussed above in general.

However, the utilities propose to charge by the hour for costs associated with preparing such information. As fully described in Exhibits 48, 49 and 50, the cost of providing such information at the request of customers or the Commission, are currently imbedded in distribution rates and information is provided without charge until it is provided a third time. As stated above, the utilities are required by statute to cooperate in this regard. Further, they are required to provide information consistent with Commission policy. Commission policy, as exemplified by the DA program and other matters, is that this information will be provided free of charge (at least twice).

The utilities, seemingly, propose to charge the CCA for something that the CCA customer has already paid through distribution rates, and then credit such funds back to all distribution customers. While the County and the City believe that an exception may be made for CCA specific load profile studies, all the other material identified within Appendix B to the utilities report on information issues should be required to be provided and should be required to be provided at no charge. None of the utilities posit a credible argument to do otherwise.

VII. ESTIMATES OF SERVICE FEES

[LACV] As stated at the hearings, the utilities do not propose the adoption of any specific charge listed in their testimony but want the approval of categories of charges for which they will later determine an actual charge in a utilities-proposed, but not scheduled, subsequent "Phase Three." The County and the City strongly object to this approach. Phase I was established to provide CCAs with an opportunity to review what charges they may face associated with community choice aggregation. The utilities in this proceeding have effectively "punted" this issue and defined various methodologies and relied on other "proceedings" to address costs, but they neither propose a cost responsibility surcharge for community choice aggregation nor propose the adoption of any specific fees. *[Se*e, Ex. 23 at 6, lines 8-9.] In light of this failure by the utilities to propose fees or rates, the Commission should adopt those rates that are currently in effect for direct access service, which the Commission has already recognized as comparable service.

A. Implementation Fees

[LACV] As discussed in cross-examination, currently the utilities recover all direct access program implementation costs through Account 376. [Tr. 146.] That account balance is then spread over all remaining customers and paid in the distribution charges to all customers. Thus, CCA customers and bundled customers alike will pay the costs of implementation of direct access programs if any such remain uncollected. As with information fees, implementation fees were not collected from direct access customers who were provided basic information and start up programs at no cost to them or the ESPs. In part, the justification for this treatment was that the direct access program was a creation of statute that the Commission was required to implement. The exact same rationale applies in this regard. AB117 is also a statutory program which the Commission is required to implement by issuing general rules and review of specific implementation plans of CCAs..

As part of the cross-examination of Ms. Osborne on behalf of SDG&E, each individual charge *(see* Section (III)(A)(4) above) was evaluated in the context of whether such a charge is assessed against direct access customers. Based on her testimony, no implementation charges have been assessed on direct access customers and, therefore, none should be assessed on CCA customers. [Tr. 637.]

[LGCC] SCE and SDG&E propose to recover their start-up costs for implementing CCA from the first Community Aggregator. That entity would then bear the burden of collecting a share of the costs from subsequently formed CCAs.[175] SCE states that these costs "can be very significant".[176] PG&E proposes to spread the cost over all ratepayers, consistent with the AB 117 requirement that all non-CCA specific costs program administration be spread over all ratepayers. [177]

[175] Exh. 7, at 12-13; Exh. 3, at 9.
[176] Exh. 7, at 30.
[177] See, Exh. 12, at 5-4; Pub.Util.Code § 336.2(c)(17); Order Instituting Rulemaking R.03-10-003, October 2, 2003, at 11.

SCE and SDG&E's position is unreasonable and unfair. Adoption of their proposal would impose a very significant barrier to CCAs and could thwart the development of any CCA, contrary to the intent of AB 117. No local governmental entity has the resources to accept this very significant risk on top of all of the other risks and costs associated with establishing a CCA. SCE and SDG&E's proposals must be rejected.

B. Fees Related to CCA Establishment

The arguments associated with implementation are equally applicable to the issues associated with establishment of CCAs. The establishment of a CCA is a one time event associated with the implementation of a statutory direction. These costs will be applicable to every CCA as they organize and are put into operation. This is not a specific transaction cost. Thus, pursuant to statutory direction, this is a cost not reasonably attributable to a single community choice aggregator and "shall be recovered from ratepayers." *[See* Section III above, at p. 13.] The SDG&E proposal that all such costs be assessed on the first CCA in a service territory is merely designed to scare away potential CCAs and penalize the first who dares to file a plan.

C. Enrollment Fees

This fee, along with the previous two, is yet another charge for program implementation but also reflects charges associated with customers who request new service within a CCA territory and who do not opt out for utility service. As discussed later, the utilities also request the collection of a fee in which customers decide to opt out. Thus, the utilities are requesting that when a customer is enrolled for CCA service, or when it opts out of CCA service, the CCA shall pay the utility. As was discussed in cross-examination of Ms. Osborne, no similar charges were or are assessed against any mass enrollment by an ESP or against any individual direct access service request (DASR) for customers entering or leaving direct access or bundled utility service. [Tr. 644, 649.] As a result, none should be assessed on CCA customers..

D. Billing Payment and Collection Fees

Section 366.2(c)(17) provides that reasonable transaction costs of notices, billing, metering, collection and customer communications or other services provided to an individual aggregator or its customers shall be recovered from that aggregator. In response to a request from the Presiding Judge, the utilities provided information in Exhibits 48, 49 and 50. Those exhibits indicate that the cost of providing such services are currently collected within distribution rates. As such, the utilities should not be able to double collect charges associated with this community choice aggregation and that a crediting mechanism is an unnecessary, inappropriate and costly complicating factor under any circumstances. The exception, however, seems to be the limited "exception" services described in Ex. 24.

E. Monthly Account Maintenance Fee

Again, such a charge is only appropriate if currently assessed on all customers – which it is not. If it is assessed on all customers, it is assumed to be collected within the distribution component of the existing utility rates. If it is so collected, it is currently collected from the CCA customer and will be continued to be collected when the customer receives CCA service as the distribution component of rates will not change. As such, no charge is appropriate.

F. Interval Metering Fees

With regard to this fee and others, Exhibit 24 provides guidance. Exhibit 24 is SDG&E "Schedule DA" which provides for the rates and charges associated with direct access customers. Consistent with the Commission order establishing this proceeding, and the direction provided by statute, the charges established within Schedule DA should be applicable to community choice aggregation service as they appear to be special services that would only be provided if requested by the community choice aggregator or the ESP on behalf of its customer or members.

Thus, certain customer request fees are exception fees as provided on Revised Sheet No. 4 of Exhibit 24 that can be and should be assessed on CCA customers. Exhibit 24 is also informative in that it provides information as to what costs are currently included within the distribution component and bundled service and are already collected in rates from customers who could become CCA customers -- and thus will continue to be charged to such customers after their switch to CCA service. Thus, the Commission should look for guidance based on its decisions related to tariffs approved for direct access service, an example of which is Exhibit 24. Each of the utilities have a version of Exhibit 24 which can provide the basis for charges in each of the individual utility territories and each supports reference to past DA decisions to provide proper guidance. [Tr. 636.]

G. Termination of CCA Fees

The bookend of the enrollment fee is the request that there be a termination program fee. Direct access service has no program start up or program termination fees, but does have penalties associated with switching related to the cost of providing power due to the switch. While the issues associated with switching rules and penalties associated with switching will be addressed in Phase II, the discussion further indicates the lack of need for either enrollment or program termination charges as none are assessed on direct access customers. Therefore, none should be assessed on community choice aggregation customers.

H. Special Request Fees

Consistent with AB 117 and the treatment of direct access customers, special request fees are appropriate and should be paid by CCAs when such special requests are made. Special requests are just that – special. They are not normal services provided to bundled customer nor are they services normally provided to direct access customers at no charge. Therefore, CCA customers should not receive such services free of charge either. However, the utilities do not propose specific charges for the special requests other than time and material. To the extent to which time and material has been an adopted methodology for special services for direct access customers, it would be appropriate for CCAs. To the extent to which there is a fee specifically.adopted for such special request for direct access customers, such as Exhibit 24, that specific fee should also adopted for CCA customers. Revisions of the charges of such fees or establishment of new fees should be handled within the next general rate case of each of the utilities.

VIII Proposed Fair Share of Costs and Fees to be Borne by Shareholders

[Local Power] The legislature did not intend to shield shareholders against bearing a fair share of transaction and procurement-related costs related to implementing AB117. While bundled service customers are limited to paying for CCA transaction and procurement costs not attributable to any particular CCA customer, the legislature did not intend that utility shareholders should be protected against costs relative to CCA. The word "shareholder" does not appear in AB117. Thus, AB117 does not protect utility shareholders from cost shifting where necessary to accommodate CCA as a permanent recourse to California ratepayers.

[CalCLERA] Moreover, AB117 was not intended to immunize IOU shareholders from bearing a fair share of the costs and risks of implementing community choice aggregation.[178]

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[178] Tr. 1037 (Fenn).

IX Credits for Benefits to the State of California and/or other ratepayers related to CCA Establishment

This subject is addressed in V, 13.

X. Utility Performance

[CCSF] CCAs will be making commitments for power deliveries, customer support, advertising, and other aspects of CCA implementation. In some cases these commitments must happen several months before the actual start date of CCA service. If utilities do not meet deadlines this could result in costly delays to CCA formation (i.e. testing of EDI capabilities or notification deadlines for customer opt-out). Absent financial guarantees from utilities regarding performance deadlines, the Commission should provide some mechanism to help ensure that utilities will meet deadlines for performance. CCSF notes that PG&E does not expect to offer any guarantees to complete work in a timely manner and will conduct the work subject to the availability of company resources.[179] As Witness Fulmer explains "…it appears that PG&E proposes to do the work for which CCAs have potentially paid in advance without any guaranteed deadlines and then only when it has the time and available manpower to work on the projects."[180] Indeed the host utility has effective veto ability over the timetable for start up of a CCA.[181] Internal competition for PG&E's resources could result in CCA matters dropping in priority, thereby

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[179] Exhibit 30 at 13.
[180] Id.
[181] Id at 14.

creating cost and scheduling problems for a CCA. CCSF recommends that CCAs be allowed to collect damages as one approach to ensuring utility performance.[182] PG&E believes the language of the existing service agreement between PG&E and ESPs is sufficient protection for CCA planning. CCSF acknowledges the treatment is similar, but certainly not identical.[183] We urge the Commission to adopt rigorous standards for utility performance in meeting the timetables that CCAs require to establish service.

XI. Conclusion

Local Power looks forward to further clarification of these issues in coming weeks,

Respectfully,

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[182] Id., Exhibit 32 at 7.
[183] RT at 803.