

**PUBLIC UTILITIES COMMISSION**505 VAN NESS AVENUE  
SAN FRANCISCO, CA 94102-3298

October 29, 2004

Agenda ID #4008  
Ratesetting**TO:** PARTIES OF RECORD IN RULEMAKING 03-10-003**RE:** NOTICE OF AVAILABILITY OF PROPOSED DECISION RESOLVING PHASE 1  
ISSUES ON PRICING AND COSTS ATTRIBUTABLE TO COMMUNITY CHOICE  
AGGREGATORS AND RELATED MATTERS

Consistent with Rule 2.3(b) of the Commission's Rules of Practice and Procedure, I am issuing this Notice of Availability of the above-referenced proposed decision. The proposed decision was issued by Administrative Law Judge (ALJ) Kim Malcolm on October 29, 2004. An Internet link to this document was sent via e-mail to all the parties on the service list who provided an e-mail address to the Commission. An electronic copy of this document can be viewed and downloaded at the Commission's Website ([www.cpuc.ca.gov](http://www.cpuc.ca.gov)).

Any recipient of this Notice of Availability who is not receiving service by electronic mail in this proceeding may request a paper copy of this document from the Commission's Central Files Office, at (415) 703-2045; e-mail [cen@cpuc.ca.gov](mailto:cen@cpuc.ca.gov).

This is the proposed decision of ALJ Malcolm, previously designated as the principal hearing officer in this proceeding. It will not appear on the Commission's agenda for at least 30 days after the date it is mailed. This matter was categorized as ratesetting and is subject to Pub. Util. Code § 1701.3(c). Pursuant to Resolution ALJ-180, a Ratesetting Deliberative Meeting (RDM) to consider this matter may be held upon the request of any Commissioner. If that occurs, the Commission will prepare and mail an agenda for the RDM 10 days before hand. When an RDM is held, there is a related ex parte communications prohibition period.

When the Commission acts on the proposed decision, it may adopt all or part of it as written, amend or modify it, or set it aside and prepare its own decision. Only when the Commission acts does the decision become binding on the parties.

Parties to the proceeding may file comments on the proposed decision as provided in Article 19 of the Commission's "Rules of Practice and Procedure." These rules are accessible on the Commission's website at <http://www.cpuc.ca.gov>. Pursuant to Rule 77.3 opening comments shall not exceed 25 pages.

Consistent with the service procedures in this proceeding, parties should send comments in electronic form to those appearances and the state service list that provided an electronic mail address to the Commission, including ALJ Malcolm at kim@cpuc.ca.gov. Service by U.S. mail is optional, except that hard copies should be served separately on ALJ Malcolm and the assigned Commissioner, and for that purpose I suggest hand delivery, overnight mail or other expeditious methods of service. In addition, if there is no electronic address available, the electronic mail is returned to the sender, or the recipient informs the sender of an inability to open the document, the sender shall immediately arrange for alternate service (regular U.S. mail shall be the default, unless another means – such as overnight delivery is mutually agreed upon). The current service list for this proceeding is available on the Commission’s Web page, [www.cpuc.ca.gov](http://www.cpuc.ca.gov).

/s/ ANGELA K. MINKIN by KH  
Angela K. Minkin, Chief  
Administrative Law Judge

ANG:tcg

Attachment

Decision **PROPOSED DECISION OF ALJ MALCOLM** (Mailed 10/29/2004)

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA**

Order Instituting Rulemaking to Implement  
Portions of AB 117 Concerning Community  
Choice Aggregation.

Rulemaking 03-10-003  
(Filed October 2, 2003)

(See Appendix A for List of Appearances.)

**ORDER RESOLVING PHASE 1 ISSUES ON PRICING AND COSTS  
ATTRIBUTABLE TO COMMUNITY CHOICE AGGREGATORS  
AND RELATED MATTERS**

**TABLE OF CONTENTS**

<b>Title</b>	<b>Page</b>
ORDER RESOLVING PHASE 1 ISSUES ON PRICING AND COSTS ATTRIBUTABLE TO COMMUNITY CHOICE AGGREGATORS AND RELATED MATTERS.....	1
I. Summary and Background.....	2
II. Procedural Background .....	4
III. Implementation and Transaction Costs.....	7
A. Allocation of Implementation Costs Between Ratepayers and Individual CCAs .....	8
B. Transaction Costs.....	11
C. Specific Transaction and Implementation Costs.....	15
1. Incremental Billing Costs .....	15
2. Incremental Call Center Costs.....	16
3. Incremental Costs for Opt-Out Provision and Re-entry Fees .....	17
4. “Detailed Processes” Outlines.....	19
5. Recovery of Implementation and Transactions Costs .....	19
IV. Cost Responsibility Surcharge .....	22
A. The CRS Model.....	22
B. CRS “Vintaging” and Utility Resource Plans .....	24
C. Unbundling of CRS Components.....	28
D. Credits or Liability for “In-Kind” Power .....	29
E. Open Season .....	31
F. Responsibility for CRS Liabilities.....	33
G. Collection of Amounts Relating to CRS Exemption for Baseline Customers.....	33
H. Exclusion for Norton Air Force Base .....	35
I. CRS True-Up.....	36
J. CRS Implementation .....	39
V. Informational Needs of CCAs.....	43
VI. Other Issues and Terms of Service .....	49
A. CCA Program Phase-In.....	49
B. CCA Requirements to Offer Service .....	51
C. CCA-Specific Load Profiles.....	51
D. Boundary Metering .....	52
VII. Comments on Proposed Decision .....	53
VIII. Assignment of Proceeding .....	53
Findings of Fact.....	53
Conclusions of Law .....	59
ORDER .....	64
Appendix A - List of Appearances	
Appendix B - Assembly Bill 117	

## **ORDER RESOLVING PHASE 1 ISSUES ON PRICING AND COSTS ATTRIBUTABLE TO COMMUNITY CHOICE AGGREGATORS**

This order resolves outstanding issues in Phase 1 of this proceeding, which addresses costs and other related matters relevant to Community Choice Aggregators (CCA) and in order to implement the provisions of Assembly Bill (AB) 117 (2002 Stats., ch. 838) that would enable CCAs to procure power for their local residents and businesses.

### **I. Summary and Background**

CCAs are governmental entities formed by cities and counties to serve the energy requirements of their local residents and businesses. The state Legislature has expressed the state's policy to permit and promote CCAs by enacting AB 117, which authorizes the creation of CCAs, describes essential CCA program elements, requires the state's utilities to provide certain services, and establishes methods to protect existing utility customers from liabilities that they might otherwise incur when a portion of the utility's customers transfer their energy services to a CCA.

Cities and counties have become increasingly involved in implementing energy efficiency programs, advocating for their communities in power plant and transmission line siting cases, and developing distributed generation and renewable resource energy supplies. The CCA program takes these efforts one step further by enabling communities to purchase power on behalf of the community.

Today's decision is the first major step toward implementing that portion of the CCA program that would facilitate energy procurement activities by cities and counties. Today's decision constitutes the beginning of our implementation of AB 117. In this implementation, we have fashioned program that is consistent

with our expressed policies with regard to resource planning, utility ratemaking and cost recovery generally. This approach to the program will protect bundled utility customers who do not have the option to transfer to a CCA from the possible cost impacts of CCA programs.

This order by itself does not resolve all issues, even those originally anticipated for Phase 1 in this proceeding. Unfortunately, the record does not provide the type of information required for final resolution of many of the cost allocation issues that are the subject of this phase of the proceeding. This order does, however, take the program as far as possible with the limited information we have by adopting interim CCA charges and service protocols.

We hope this decision provides the type of guidance CCAs and prospective CCAs will need in determining whether to pursue energy procurement efforts in advance of our final order in Phase 2. The order should also provide some guidance to the parties about how we envision the CCA energy procurement program in the broadest sense, and the costs that CCAs will have to incur as customers of and partners with the utilities.

This order adopts the following:

- Department of Water Resources' (DWR) methodology for estimating the cost recovery surcharge (CRS), which will allow the utilities to recover from CCAs the costs of DWR bonds and contracts, utility power procurement contracts and other items in a way that remaining bundled utility customers are indifferent to the CCA program;
- A temporary CRS in the amount of \$.022/kWh, which will be trued up in 18 months or sooner, if final utility estimates of CRS are 30% lower or higher than \$.022/kWh, and thereafter will be trued up annually;
- A requirement that the utilities provide CCAs an opportunity to take delivery of power from DWR contracts through a physical allocation of these power purchase contracts;

- Principles for setting prices for utility services offered to CCAs;
- Ratemaking and cost allocation principles for utility services offered to CCAs, implementation costs and the CRS;
- A method to allocate amounts related to the CRS exception for baseline customers;
- An exception from the CRS for certain load attributable to Norton Air Force Base;
- Requirements for and conditions under which CCAs can acquire customer information from utilities needed to manage energy procurement by CCAs;
- Application of AB 117 as it relates to CCA program phase-ins, boundary metering and the use of CCA-specific load profiles.

## II. Procedural Background

The Commission opened this rulemaking on April 27, 2004 to implement certain provisions of AB 117 (Chapter 838, September 24, 2002), which added Pub. Util. Code §§ 218.3, 331.1, 366.2, 381.1, and 394.25 and permits local governments the opportunity to aggregate energy procurement on behalf of the citizens and businesses in their communities.<sup>1</sup>

AB 117 involves Commission-jurisdictional utilities by requiring them to continue to provide distribution, metering and billing services to the CCA's energy customers, among other things. AB 117 also directs the Commission to ensure that the utilities are able to recover certain costs, including those

---

<sup>1</sup> AB 117 also enables local government to pursue demand side management programs to reduce their community's energy usage, including increased coordination with Public Goods Charge (PGC) energy efficiency and conservation program administrators and the ability to apply for PGC administration and funding for energy efficiency and conservation programs on behalf of their customers. We address this issue in Rulemaking (R.) 01-08-028.

associated with energy contracts signed by the state's DWR and the costs of providing ongoing services to CCAs and their customers.

Following a prehearing conference on November 26, 2003, and with the agreement of all active parties, the Commission bifurcated the proceeding so that the Commission would first consider issues relating to certain utility costs that would be assumed by CCAs and later consider issues more concerned with transactions between CCAs, utilities, and energy customers.

A key issue in this proceeding is the level of the cost responsibility surcharge (CRS), which would permit the utilities to recover the costs of certain energy contract commitments. Utilities are concerned that the CRS be set so that they recover related costs. Utilities also want assurance that they are able to recover other discretionary costs incurred to implement and facilitate the CCA program. Entities that might become CCAs state that the level of the CRS and other utility charges will determine the viability of CCAs. Some state that the existing CRS exception for baseline residential Direct Access (DA) customers should also be applied to CCA customers.

Several parties also suggested that CCA information requirements should be addressed sooner rather than later. Parties generally agreed, however, that modifying Rule 22 and Rule 25 to govern transactions and operations of CCAs and utilities is an exercise that should follow resolution of cost issues.

Consistent with the parties' agreement and the record developed in hearings, this Phase I order addresses the following issues:

- a. The cost responsibility surcharge – cost elements that should be included in this surcharge in fulfillment of AB 117; allocation of responsibility for the costs and whether they are nonbypassable;
- b. CRS exception for baseline residential customers – whether the utilities should pass along these subsidies to CCA customers and, if so, how to accomplish that;



- c. Utility transition, implementation and transaction costs – estimating, allocation and setting cost allocation mechanisms for creating and maintaining the CCA program;
- d. Meter, billing and distribution costs;
- e. Utility customer information – information CCAs and prospective CCAs need to determine viability of CCA service and promote good customer service and reliability costs.<sup>2</sup>

The Commission held hearings on these issues in June 2004. Parties that filed briefs are Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas and Electric Company (SDG&E), Office of Ratepayer Advocates (ORA), Local Government Commission Coalition (LGCC), California Clean Energy Resources Agency and the City of Victorville (CalCLERA), Local Power, the County of Los Angeles and the City of Chula Vista (LA/CV), City and County of San Francisco (CCSF), Inland Valley Development Agency (IVDA), Toward Utility Rate Normalization (TURN), ElectricAmerica, and the King’s River Conservation District (KRCD) filed briefs.<sup>3</sup> The California Department of Water Resources provided extensive information about the cost of

---

<sup>2</sup> Phase 2 in this proceeding will address the following issues:

- 1. Customer notices required of utilities and CCAs;
- 2. Customer protections and switching protocols;
- 3. Operational protocols and load balancing;
- 4. Billing, metering and distribution services;
- 5. Reentry fees and switching fees;
- 6. CARE – discounts to low-income customers; and
- 7. Other unresolved issues.

<sup>3</sup> Occasionally, this order refers to parties that are “CCAs or prospective CCAs.” In so doing, the order is referring to all or some subset of LGCC, CalCLERA, LA/CV, CCSF, IVDA, Electric America and KRCD.

the state's electric contracts and models for estimating associated liabilities, and submitted a memorandum suggesting how the Commission should implement the cost responsibility surcharge.

This phase of this proceeding was submitted on July 23, 2004 when reply briefs were filed.

### **III. Implementation and Transaction Costs**

AB 117 addresses how the utilities would recover the costs they incur to accommodate the CCA program and provide related services to CCAs. Section 366.2(c)(17) provides general guidance about how the utilities may recover costs associated with CCA program implementation and services.

“An electrical corporation shall recover from the [CCA] any costs reasonably attributable to the [CCA], 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 [CCA] shall be recovered from ratepayers, as determined by the Commission. All reasonable transaction-based costs of notices, billing, metering, collection and customer communications or other services provided to an aggregator or its customer shall be recovered from the aggregator or its customers on terms and at rates to be approved by the Commission.”

The section refers generally to “implementation” costs and a subset of implementation costs called “transaction” costs, which it specifies are those costs related to billing, metering, customer communications and other customer costs. We infer from the language of the section that implementation costs are those associated with setting up the CCA program, and the infrastructure required to maintain and operate it. Such costs might include those associated with computer programming and data base development, and other overhead costs.

Implementation costs would include all costs except those that are identified as “transaction” costs in AB 117, such as metering and billing costs conducted on behalf of an individual CCA. We address transaction costs and implementation costs separately below.

In general, we consider how to allocate and permit recovery of CCA program costs consistent with the statute. Where the statute provides the Commission with discretion, we treat CCAs as customers who are buying services from the utilities. With that in mind, we apply ratemaking and cost allocation principles that is comparable to those applied to other utility customers. Where there exist special circumstances or conditions that favor different treatment of CCA costs, we make exceptions to this general rule, consistent with AB 117.

**A. Allocation of Implementation Costs  
Between Ratepayers and Individual CCAs**

The utilities and prospective CCAs differ in their interpretation of AB 117 with regard to allocating AB 117 implementation costs among CCAs, their customers and utility ratepayers more generally. “Implementation costs” in this context are those costs of establishing the CCA program and serving CCAs that are not identified as “transactions cost” pursuant to Section 366.2(c)(17).

SCE and SDG&E argue that CCAs and their customers must assume all CCA implementation costs, citing the portion of AB 117 that requires the electric utility to “recover from the CCA any costs reasonably attributable to the CCA, as determined by the Commission, of implementing this section.” Assuming there are some implementation costs that are not directly attributable to a single CCA but are reasonably allocated to CCAs, SCE proposes two models for allocating costs among CCAs. The first would allocate all costs to the first CCA and

provide a refund to that CCA when subsequent CCAs pay their proportional share. The second would estimate the number of CCAs and establish charges accordingly. SCE would true-up the mismatch between estimated and actual revenues, and subsequently refund or charge CCAs accordingly. SDG&E argues that AB 117 does not permit cost-shifting of any type and that imposing implementation costs on the general body of utility ratepayers would represent cost-shifting.

PG&E would allocate “a minimum level” of “basic implementation costs,” such as computer programming, to all ratepayers. It would charge “exceptional” implementation costs to individual CCAs. PG&E identifies these services as customized to the CCA and argues that it is not required to provide such services. ORA concurs with PG&E to the extent that it has concerns that startup costs could become an insurmountable barrier to the creation of CCAs. ORA argues that the program generally will benefit all ratepayers because they may at some point have an opportunity to choose service from a CCA. Accordingly, ORA proposes that utilities’ ratepayers “loan” CCAs the costs of upfront funding, to be repaid in increments when CCAs initiate service during each open season.

CCSF, LA/CV, and King’s River concur with PG&E that some costs should be allocated to all ratepayers, citing Section 366.2(c)(17) which states “Any costs not reasonably attributable to a CCA shall be recovered from ratepayers, as determined by the Commission.”

**Discussion.** AB 117 requires CCAs or their customers to assume any costs incurred on behalf of individual CCAs. Based on the plain language of the statute, we find that those costs which may be identified as being incurred on behalf of a CCA should be assumed by the CCA and its customers. Those costs

that cannot be associated with an individual CCA may be allocated to all ratepayers, at the discretion of the Commission. If the Legislature intended that no CCA program implementation costs be allocated to all ratepayers, we must assume that it would not have required that utility ratepayers assume program costs “not reasonably attributable to a CCA.” The choice of the phrase “a CCA” in this context also supports the CCAs’ interpretation of the statute. If the Legislature had intended that the general body of ratepayers assume no implementation or transaction costs, this phrase would have said “not reasonably attributable to CCAs.” That construction, however, would appear superfluous because the statute does not address the treatment of costs incurred by entities other than CCAs.

The statute gives the Commission discretion to establish which costs should be borne by utility ratepayers and we find that the assumption of implementation costs by such ratepayers is not “cost-shifting.” Our interpretation of Section 366.2(c)(17) reflects our view that, while AB 117 would limit the cost liability of customers remaining with the utility, it recognizes that some program costs could not reasonably be assumed by a single CCA without creating insurmountable practical problems or barriers to entry that the statute probably did not intend.

The question then is which costs are attributable to individual CCAs and their customers and which are more appropriately allocated to utility ratepayers. We agree with PG&E that individual CCAs should not assume the costs of developing the CCA program’s basic infrastructure. The CCA program is supported by the state’s legislature as good public policy and one that will promote the state’s interests. For that reason alone, we do not consider future CCAs and their customers as the sole beneficiaries of the program. We also wish

to avoid the practical problems associated with isolating infrastructure costs and allocating them to individual CCAs as SCE proposes, for example, by charging early CCAs the bulk of the costs and refunding them later. This formula is complex and would present a significant artificial barrier to the creation of CCAs. ORA's suggestion that utility ratepayers "loan" CCAs the costs of program startup is also untenable because of its complexity and the uncertainty it creates for CCAs. For these reasons, the costs of developing the CCA program's infrastructure should be assumed by all customers, both CCA's and utility's.

We adopt PG&E's proposal to allocate basic startup implementation costs to all customers and to charge individual CCAs the costs of specific specialized services. We will direct all three utilities to design tariffs accordingly. The utilities should account for these costs as they would any infrastructure costs, whether in capital accounts or expensed. We will address the issues of cost recovery from ratepayers more fully in a subsequent section of this order.

### **B. Transaction Costs**

Section 366.2(c)(17) requires that "all reasonable transaction-based costs of notices, billing, metering, collections, and customer communications or other services provided to an aggregator or its customers" be recovered from the CCA or its customers in rates.

The utilities presented a list of the types of costs that should be recovered from CCAs or their customers and also the methods for determining the related rates. They did not propose final specific cost recovery from ratepayers in this phase of the proceeding, seeking to develop those allocation of costs in Phase 2.

The utilities generally propose an "incremental costing methodology" to base charges to individual CCAs for tariffed services. This methodology

would recognize the additional costs the CCAs impose on the system. The utilities propose that all transaction costs, including those that might be incurred for a single service, be charged directly to individual CCAs. In some cases, they propose to charge CCAs for services for which they are already reimbursed in existing rates. In those cases, SCE and PG&E would account for CCA revenues as “Other Operating Revenue” and subtract them from the utility’s revenue requirement.

Other parties generally agreed with the incremental costing methodology in concept but raised concerns about the ways the utilities applied the principle. LGCC suggests the Commission order the three utilities to develop a consistent and transparent methodology. To that end, LGCC would have the utilities prepare a joint exhibit that describes (1) services to be provided; (2) the details of utility proposals for providing the services; and (3) costs related to current tariffs for similar services to direct access customers. LGCC proposes that the actual level of service charges be adopted in Phase 2 of this proceeding. LA/CV states that, as a matter of fairness, the utilities should not be able to charge for any service for which existing customers do not currently pay. They also suggest that tracking and monitoring associated costs and changing rates will present practical difficulties.

CCSF argues that the utilities’ cost estimates must recognize the operational cost savings that the utilities will realize from CCA formation and operation. CalCLERA proposes that the utilities’ rates recognize the more global benefits of CCAs to California and its customers associated with reduced risk, reduced wholesale power costs, and economic development.

Related to the utilities’ costing methodology is the issue of whether to apply existing charges for direct access customers to CCAs and their customers

for identical transactions and services. The utilities argue that these charges should not be applied because they are out of date, having been adopted in 1997. Other parties argue that they are reasonable for the time being. If necessary to avoid delay of CCA program implementation, LGCC and King's River suggest utilities apply direct access tariffs in the interim. ElectricAmerica presents similar arguments and believes the Commission should find a way to credit CCAs for the fees they have paid the utilities to develop information infrastructure.

**Discussion.** We adopt the utilities' incremental costing methodologies because conceptually those methodologies would protect bundled customers from cost-shifting, prevent the utilities from realizing unreasonable profits from the CCA program and conform to the statute's requirement that costs associated with a CCA be charged to a CCA. Although we adopt the costing methodologies the utilities propose, we do not apply them as they would in all cases. Costs for which the utilities are already reimbursed in the utility revenue requirements shall not be charged to CCAs at this time. For example, utilities today recover the costs of the billing system and customer service calls. If CCAs were charged for these services, the utilities' shareholders would receive a windfall except to the extent the customer's bills reflect only those additional costs imposed on the system by the CCAs. The utilities' proposal to implement the charges now and credit "other operating revenues" does not cure this problem prior to a general rate case order. Because general rate cases incorporate "other operating revenues" into the revenue requirement on a forward-looking basis, the utilities would receive a windfall between the time they implement the CCA charges and the time of the next general rate case order. If the utilities wish to propose to unbundle CCA services for which they are already reimbursed, such as customer service inquiries, they may propose to do so in their future general rate cases.



Until that time, their CCA tariffs should not include any costs for which the utilities are already reimbursed.

As CCSF and King's River suggest, we also expect the utilities' fees to recognize the operational cost savings that might occur with CCA formation. To the extent that the utilities' cost methodologies really do reflect incremental costs, their proposed fees will incorporate program cost savings. We are not prepared, at this time, to quantify the benefits of the CCA program on the state's energy or economic infrastructure, as CalCLERA proposes. While there may be such benefits, we do not have before us an adequate record to develop an associated methodology and their estimation would be highly speculative. Parties may raise this issue in the future if they are able to present reasonable methods for estimating these benefits, supported by an adequate record.

Unfortunately, and in spite of the Commission's intent, we do not have a complete record to adopt final charges in this phase of the proceeding. The parties representing prospective CCAs agreed to bifurcate this proceeding at the urging of the utilities with the understanding that to do so would provide them with an early understanding of the charges they would face as CCAs and in order to determine whether it would be worth their time and resources to proceed to Phase 2. In spite of this understanding, the utilities have stated they have not had the opportunity to create the tariffs anticipated in R.03-10-003. They have now had a year to create those tariffs since the initiation of this proceeding and another year prior since the Governor signed AB 117. By this order, we direct the utilities to submit proposed tariffs consistent with this order no later than 30 days following the effective date of this order for consideration in Phase 2 of this proceeding.

In the meantime, we will not suspend progress toward implementation of the CCA program to accommodate the utilities' delay in presenting final tariff proposals. Instead, we direct the utilities to use existing direct access tariffs until their CCA tariffs are approved and final as suggested by several parties, including LGCC, King's River and ElectricAmerica. We believe that the charges in direct access tariffs may provide a reasonable proxy for costs while we finalize CCA charges.

In sum, we adopt the utilities' proposed costing methodologies for those services which are not already included in the utilities rate base. Any service for which the utility is already reimbursed, at any level, shall not be included in CCA tariffs at this time. The utilities are ordered to submit and serve tariffs consistent with this order within 30 days of the issuance of this order. We intend to approve final tariffs in Phase 2 of this proceeding and direct the utilities to apply the direct access CRS tariffs in the meantime.

We discuss several specific tariff proposals in following section.

### **C. Specific Transaction and Implementation Costs**

#### **1. Incremental Billing Costs**

SCE and SDG&E state they will have incremental billing costs because they will have to receive usage and other information from the CCA, then bill the customer on a separate page from the utility's bill, then remit the payments to the CCA. CCSF proposes that the utilities unbundle billing services so that inquiries about billings are charged separately, as with direct access customers. CCSF also proposes that when an inquiry is required to reconcile a utility error, the CCA should not be charged.

**Discussion.** We agree with the utilities that the CCA program will impose incremental billing costs beyond those that are already included in utility revenue requirements. The utilities should estimate those costs consistent with this order and propose a recovery that does not include the costs of mailing the bill to the customer, since those costs are already recovered in existing customer bills.

We also adopt CCSF's proposal for unbundling billing processing fees. We agree that a CCA should not be required to pay for a service that it may choose not to use and should not incur fees for billing errors attributable to the utility.

## **2. Incremental Call Center Costs**

SCE states it will incur incremental costs relating to helping customers at its call centers. CCSF objects to the utilities' proposals to charge for such calls since other customers do not pay individually for those calls. CCSF proposes these costs be assumed by ratepayers as a group, as they are currently.

**Discussion.** We are not convinced that the CCA program will significantly increase the number of calls to utility call centers. Because the utilities already recover the costs of customer call center operations in customer bills, and assuming CCA customers do not call the utilities more frequently than they would as utility bundled customers, the utilities are not penalized if they do not charge CCAs for CCA customer calls. To the extent that the utilities are able to demonstrate in future general rate cases that a CCA program has caused incremental costs to operate the call centers to address CCA business matters, we will consider approving an associated fee at a later time. In that case, we would expect the utilities to make corresponding reductions to the revenue requirement for call center services to bundled customers. In addition, fees to CCAs should

not include the costs of calls that concern utility services. While CCAs should ultimately pay for the services they or their customers receive, they should not be charged for calls that involve utility distribution, transmission, or other utility services.

### **3. Incremental Costs for Opt-Out Provision and Re-entry Fees**

SCE and SDG&E believe they will incur incremental costs relating to the “opt-out” provision of AB 117, that is, the option for utility customers to remain bundled utility customers rather than transfer to the CCA. SCE argues that neither its shareholders nor its remaining ratepayers should assume liability for those costs. ORA suggests the initial implementation costs for this part of the program should be assumed by the general body of utility ratepayers. After that, ORA argues that utility shareholders should assume the cost of luring a customer back to its bundled service. ORA believes it would be “fundamentally unfair and against the basics of a competitive market place to make a CCA pay its competitor’s cost of taking away its customer.”

CCSF proposes that utility ratepayers assume the cost of processing the opt-out provisions of the CCA program, while recognizing that the opt-out notification costs are allocated to CCAs by the statute. CCSF also believes it is inappropriate for the utility to charge the CCA an opt-out fee for the cost of transferring a CCA customer back to the utility. LA/CV makes similar points.

**Discussion.** Start-up costs associated with implementation of the opt-out provision should be assumed by the general body of ratepayers. These costs may be considered “implementation” rather than “transaction” costs as the statute uses that term because they are primarily incurred to implement CCA

programs in general rather than serving individual CCAs or CCA customers. The costs the utilities incur to create, mail or otherwise facilitate a CCA's notification shall be included in utility tariffs.

As CCSF, LA/CV and ORA suggest, the cost of transferring a customer from the CCA to the utility should not be assumed by the CCA. With regard to "re-entry" fees referred to in R.03-10-003, we find that the utility may charge the customer for the transfer back to the utility once that customer is again a bundled utility customer, consistent with Section 366.3(c)(11), which provides that CCA customers shall be subject to the same terms and conditions as returning direct access customers. For customers with large load, we also believe the re-entry fee should reflect the cost of incremental procurement and reliability. However, the CCA should not have to assume the cost of activities that ultimately deprive the CCA of a customer.

SDG&E suggests utility customers receive a notice of the CCA program in advance of the CCA's notice. These preliminary notices would give customers information about the program and the release of customer information. We agree this notice might provide important information to customer about potential changes in service. We also find that the cost of these notices should be assumed by the general body of utility ratepayers as start-up costs and consistent with the Commission's treatment of all customer notices regarding changes in markets and rules, and utility programs and services. If a utility chooses to send such a notice, it shall receive review from the Commission's Public Advisor office of its draft notice to assure the notice may not be misconstrued as a marketing tool for utility services. The notices shall provide basic information to customers explaining what the CCA will do, and how it may affect relevant customers and their service options.

In sum, we herein allocate the costs of the start up costs for opt-out provisions to each utility's general body of utility ratepayers. CCAs shall assume all costs associated with their own opt-out notices. The utilities shall not charge the CCA for the CCA customer's transfer back to the utility once the customer becomes a utility customer. The utilities may charge these customers a re-entry fee for such a transfer, once they again become a utility bundled customer, including a fee that reflects procurement liabilities in the case of customers with large loads.

#### **4. "Detailed Processes" Outlines**

SCE, PG&E, and SDG&E each developed an initial proposal of "detailed processes" required to implement the CCA program. The utilities discussed these outlines with all interested parties at Commission workshops conducted prior to evidentiary hearings and were subsequently included in the utilities' testimony. SDG&E asks the Commission to adopt the specific processes in Phase 1 to facilitate Phase 2 of this proceeding, where the Commission will be addressing terms of service and operational issues. Except as discussed in other sections of this order, no party took issue with the content of these outlines.

The detailed processes outlines are useful explanations of internal procedures and form a reasonable foundation for considering cost and processing issues. Unless stated otherwise in other parts of this order, we state our intent to use them as foundation for future CCA program tariffs and further development of operational issues in Phase II of this proceeding.

#### **5. Recovery of Implementation and Transactions Costs**

The utilities propose accounting mechanisms to ensure that they are made whole for the costs they incur to implement AB 117. SCE proposes a

memorandum account and seeks funding for CCA program implementation in advance. PG&E would include a forecast of CCA costs in its distribution revenue adjustment mechanism with a true-up at a later date, which is substantially similar to SCE's proposal. LGCC suggests the Commission adopt a forecast of utility costs and hold the utilities to that amount.

PG&E and SCE propose to update transaction costs by way of advice letters, which would be deemed automatically effective within 40 days unless protested, or suspended by Commission staff.

Local Power and other parties oppose upfront funding of implementation costs, arguing that CCAs are captive customers of the utilities for many services and should not be subjected to extraordinary financial burdens.

**Discussion.** We agree with the utilities that, for initial program costs prior to general rate case review, implementation costs should be recoverable dollar-for-dollar. We refer here only to implementation costs that would be recovered from the general body of utility ratepayers and ultimately subject to review in general rate cases. We take this step to permit the creation of balancing accounts only for the period prior to each utility's next general rate case. For subsequent periods, the utilities should treat CCA costs like those incurred for any other customer service or operation cost and include the amount in the general rate case revenue requirement.

CCAs would be customers of the utilities and, consistent with our treatment of the operational costs of serving other customers, the utilities should assume some risk for serving them and be able to reap the benefits of cost savings they implement between general rate cases. Moreover, CCAs should not have to assume liabilities for infrastructure development in advance. Such a

requirement would be unprecedented in our treatment of utility customers and is unjustified here.

Consistent with the foregoing discussion, the utilities shall establish memorandum accounts for the initial period of program implementation and prior to their next general rate cases. As part of their respective general rate cases, they should recover those costs and propose forward looking CCA implementation and infrastructure costs as part of their revenue requirements, consistent with treatment of similar costs for other types of customers.

Similarly, we will permit the utilities to develop balancing accounts and apply changes only prospectively for transaction costs. Instead, these costs should be forecast based on costs and, as the utilities propose, imposed on CCAs directly and included in tariffs. CCAs, like all customers, are entitled to some expectation that their charges will be predictable and subject to review by the Commission. As we suggest in our discussion of implementation costs, we are concerned that open-ended balancing accounts and true-ups will undermine incentives for cost containment by the utilities. Moreover, as LA/CV suggests, we wish to avoid constant litigation concerning the level of dozens of possible tariffed charges, which would be expensive for the utilities, the CCAs and the public. The utilities should track their transaction costs to justify prospective changes to charges included in CCA tariffs, which we will consider in general rate cases. We will not consider changes to CCA tariffs between general rate cases or, where general rate cases are deferred, more than every three years. In the latter case, we will consider utility applications for CCA changes. Between general rate cases, utilities may file advice letters if they wish to propose changes in CCA tariffs to components other than increases to existing



rates, or for new services or to reflect changes in the industry or CCA program operation.

#### **IV. Cost Responsibility Surcharge**

Section 366.2(d)(1) of AB 117 provides that the costs associated with CCA's procurement of power for local residents and businesses must not require remaining utility customers to assume additional costs, that is, those power procurement costs that would be unavoidable when the utility loses customers to the CCA. In that way, AB 117 anticipates "ratepayer indifference" to the CCA program. No party disputes this principle, although how to calculate and implement the CRS raises some complex and somewhat controversial related issues, discussed below.

The Commission has already adopted such surcharges for other types of customers who stop taking power from the utility, including those depart from all utility services and generate their own power, direct access customers and departing load customers of municipal utilities that reduce their demand from the utility in favor of other power procurement resources. Where possible, we apply the lessons learned and the policies adopted in those cases to the CRS we adopt for CCAs.

##### **A. The CRS Model**

All parties agree that AB 117 requires the CCA CRS to include a variety of costs incurred on behalf of CCA customers prior to their transferring to the CCA. Such costs include (1) costs associated with power contracts and bonds entered into by DWR during the energy crisis; (2) utility power costs, including those of utility retained generation, purchased power and other commitments in approved resource plans; and (3) CTC and historic revenue undercollections and

credits applicable to the customer at the time the CCA transferred the customer. No party disputes these cost elements.

The CRS model that was the basis for most discussion was presented by DWR and operated by Navigant Consulting. In general, DWR recommends that the Commission adopt for CCAs its CRS methodology, which is referred to variously as “CCA-in/CCA-out,” “total portfolio” model or the “indifference fee” approach. This methodology analyzes the liabilities that would otherwise be assumed by bundled utility ratepayers when the CCA begins serving local customers. Those liabilities would then be incorporated in the CRS so that bundled utility ratepayers are not penalized from the utilities loss of energy customers. This methodology is the one adopted in D.02-11-022 for direct access customers.

In a memorandum to the Commission dated July 9, 2004, DWR presents several recommendations on how to implement the CRS in a way that prevents cost-shifting and promotes administrative simplicity and revenue certainty, where applicable. It did not present a final proposed cost allocation in this proceeding but agrees to work with the Commission and utilities following its resolution of outstanding controversies in how to set the CCA CRS.

The utilities and most parties support DWR’s “CCA-in/CCA-out” methodology and truing up the difference between the forecast and actual costs annually. SDG&E recommends removing from DWR illustrative calculation SDG&E’s CTC and bond charge, nonbypassable components applied to the direct access customers that are not relevant to the calculation of a CRS for CCAs. SDG&E also argues against a cap on the CRS, which the Commission applied to direct access customers.

**Discussion.** No party challenges the utilities' proposal with regard to the types of costs that should be included in the CRS or even the methodology DWR presents. The methodology has been subject to considerable scrutiny in other proceedings and it is reasonable to adopt it here.

The CCA CRS should be calculated separately from the CRS for direct access customers to reflect the utilities' concurrent power purchase liabilities, which may differ from those incurred in previous years. We direct the utilities to impose the CRS on new customers as well as existing customers because both would have been required to assume those liabilities if they had taken service from the utility rather than the CCA. In addition, the CRS should incorporate any refunds to or credits associated with the accounts, bond charges and power purchase contracts that are subject to CRS treatment, which SCE proposes and no party opposes. Consistent with our view that the CRS for each CCA should reflect the costs incurred on behalf of CCA customers, the CRS for each CCA in each period should reflect the cost savings or refunds associated with commitments made on behalf of those CCA customers. The CRS should not include any avoidable costs, such as ISO charges for ancillary services.

### **B. CRS "Vintaging" and Utility Resource Plans**

The creation of CCAs and transfer of utility customers to them will change the utilities' load and resource plans. The utilities propose that in order to prevent cost-shifting to remaining bundled customers, the CRS must include costs for power procurement commitments they could not otherwise recover or reduce. No party disputes this general notion but some question how it will be applied.

The parties addressed whether and how the CRS should change at regular intervals to reflect changes in utility portfolios that might increase or

reduce power purchase liabilities, an exercise referred to as “vintaging.” The CCA would then assume liability going forward for only those DWR and utility liabilities that were current at the time the CCA began its operations. The utilities and other parties generally agree that vintaging this portion of the CRS is appropriate to reflect the utilities’ prevailing power cost liabilities and to assure CCA customers pay for those resource commitments, and only those commitments, that were incurred on their behalf.

SCE proposes that CCA customers be required to pay for all utility procurement incurred up to the date that service is switched from utility service to the CCA. LGCC opposes this, arguing that Section 366.2(f)(2) permits only the recovery of “unavoidable” electricity purchase contract costs that are “attributable to the customer.”

PG&E would have the Commission vintage CCA charges only after all long-term procurement matters have been resolved, including those implicated in Phase 2 of this proceeding, and the procurement docket, R.04-04-003. PG&E is especially concerned that issues relating to switching be resolved so that PG&E can plan for procurement contingencies in its role as provider of last resort.

LA/CV and most parties agree that the utility and its bundled customers should assume full responsibility for any “New World” procurement costs and risks assumed after the CCA is established. LGCC would go further by excluding from the CRS costs from any contracts signed after the passage of AB 117.

LA/CV express concern that SDG&E, and potentially other utilities, may fail to consider changes in their resource plans to reflect future changes in load resulting from CCA operations. LA/CV argues that SDG&E has already failed to reflect CCA load in its recently-signed power contracts (approved in

D. 04-06-011) even though it was aware that the City of Chula Vista had created a CCA in mid-2001. It argues that SDG&E “appears to be racing to establish contracts in a manner that will force CCAs to subsidize such purchasing decisions...”

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

We agree with the parties that the CRS must change to reflect changes in the utilities’ resource portfolios and will order the utilities to establish an annual CRS that incorporates the concept of vintaging. Although PG&E suggests we delay this practice, we intend the utilities to implement it immediately in order to reflect the actual outstanding liabilities in their energy portfolios. We take PG&E’s concerns seriously with regard to the many elements of long-term planning that are implicated by the CCA program. On the other hand, PG&E seems to argue that implementing various rules will make its forecasting job substantially simpler. However, we are not convinced that implementing a switching rule and finalizing a single long-term resource plan will alone substantially reduce forecasting uncertainty. Utility resource plans will need to balance supply security with enough flexibility to accommodate many market contingencies in addition to those associated with the CCA program, as we have recognized. Although we agree with PG&E that vintaging must reflect prevailing portfolio characteristics and market conditions, we reject PG&E’s argument that the Commission reject vintaging in concept in advance of resolving the many related resource planning issues. Because it would ideally

recognize and anticipate changing markets and supply sources, resource planning will necessarily be an ongoing, interactive exercise.

We do not agree with LGCC that the CRS should exclude any energy commitments entered into following passage of AB 117. As long as the utilities have made reasonable assumptions about future electricity demand, the CRS must include all stranded costs that occur when customers transfer their accounts to the CCA. With few exceptions, the utilities have had little basis on which to forecast reductions in load that would occur as a result of AB 117.

On the other hand, SCE's proposal to include in the (vintaged) CRS all contract costs incurred up to the date customers transfer to the CCA is not consistent with the law. There will surely be circumstances where contracting for more energy, assuming all CCA load, would be "avoidable" and where those commitments would not be "attributable to the customer." We share the parties' concerns that the utilities must recognize CCA load in their resource planning and should not sign contracts that might create new liabilities for CCA customers and utility customers where available information suggests the power might not be needed. We understand the utilities face a difficult balancing act by assuring adequate and reliable power supplies in amounts that reflect forecasts that are changing constantly. However, the utilities are accustomed to using available information to forecast customer demand and should incorporate CCA load losses into their planning efforts, just as they would include any other forecast variable related to expected changes in supply or demand.

We will address these matters in more depth in the utilities' resource planning applications and related dockets. With this in mind, we state our commitment to continue to coordinate CCA program elements with our

oversight of utility procurement portfolios and resource planning. This should minimize unneeded power purchases by utilities and therefore the CRS.

### **C. Unbundling of CRS Components**

LGCC proposes the CRS be unbundled in order to permit a comparison of each component of the CRS with market benchmarks. LGCC expresses concern that the model currently cannot be understood by any except modelers at DWR and Navigant. Unbundling would make the model components more transparent. LGCC believes unbundling would obviate the need for frequent true-ups and will promote better decision-making by CCAs.

TURN, ORA and SDG&E support some unbundling on customer bills. SDG&E bills for past power purchases with a Competitive Transfer Charge (CTC) that is separately stated on customer bills and therefore need not be included in the CRS. SCE proposes that the Commission confirm that its current CTC would be imposed on CCA customers. PG&E has a “historic utility charge,” which should be identified on customer bills the way SDG&E has unbundled its CTC.

**Discussion.** We understand LGCC’s concern that the CRS model is not transparent to most and that identifying cost components individually may provide CCAs and customers with more of the kind of information they need to make good decisions. On the other hand, we cannot tell from the record exactly what LGCC’s proposal entails beyond requiring the utilities to break down the CRS components according to the types of costs they incur. LGCC does not make a convincing case that we should abandon DWR’s model for forecasting those components.

In order to address some of LGCC’s concerns with regard to the components of the CRS relating to utility costs, we direct the utilities to provide

calculations of each utility cost component, a description of each related assumption, and an explanation of how each component conforms to this decision to Energy Division staff and any party so requesting that information. The remaining components would relate to DWR costs. The Energy Division will consider requests for a workshop to discuss the information the utilities and DWR provide. To the extent such information is confidential, the utilities and DWR shall require parties to sign nondisclosure agreements.

We will also direct the utilities to propose a tariffed offering that unbundles CRS elements on CCA customer bills that are not already unbundled or which they do not plan to unbundle.

#### **D. Credits or Liability for “In-Kind” Power**

The CRS is intended to collect liabilities associated with power purchase contracts entered into by DWR and the utilities. These liabilities would become “stranded” if utility customers become CCA customers in the absence of the CRS. Because CCAs would be paying for this power, some suggest they should be entitled to take delivery of the power.

Cal-CLERA and King’s River propose that the Commission order the utilities to provide energy to the CCAs in proportion to their CRS liability. SDG&E and SCE argue that CCAs are not entitled to these utility assets and that AB 117 does not suggest this is an option. SCE recommends that if the Commission were to require an assignment of power to the CCA that it should require the CCA to take all power assigned to CCA customers rather than only the power that is priced above market. SCE and DWR believe there may be administrative difficulties transferring power liabilities to CCAs. PG&E argues that it cannot assign a power contract or part of it to another entity.



**Discussion:** We believe that a solution is available to address the concerns of both the utilities and prospective CCAs. Prospective CCAs would like to receive power from specific DWR contracts, which constitutes a physical allocation. The physical allocation of power from the DWR contracts to CCAs may entail some negotiations and the development of service agreements. We recognize that financial liability of the DWR contracts should remain with DWR, and do not support the financial assignment of any DWR contracts to CCAs at this time. We should not pass on an opportunity to minimize the state's liability for overpriced and otherwise stranded assets on that basis. To the extent CCAs are not permitted to take delivery of power for which they pay, the only beneficiaries of related energy contracts are power sellers who provide no service or commodity. We doubt whether the Legislature in its enactment of AB 117 would endorse a circumstance wherein an entity of local government and its citizens are required to pay for energy supplies they do not receive and which could be provided at little or no cost.

Nor do we understand the utilities' view that a CCA who takes part of a contract obligation should have to assume the entire contract obligation. If that proposal is intended to present a deterrent to or penalty for the economic use of an asset, we decline to adopt it. PG&E's argument that it cannot assign only a portion of a contract "since scheduling and dispatch rights under a contract generally reside with only a single party" seems to be circular reasoning: it cannot assign rights to a portion of the contract because it has the only rights to the contract. DWR recognizes PG&E's concerns with regard to the administration of allocating contract portions to CCAs but recommends the Commission explore this approach as a way to mitigate stranded costs.

We herein state our policy that a CCA should have the opportunity to take delivery of any portion of a DWR or utility contract for which it pays through the CRS. We expect the utilities to make every reasonable effort to affect this policy by working with DWR and the CCAs who express interest in this option. Interested CCAs should have the option to receive the physical allocation of power from DWR contracts.

### **E. Open Season**

SDG&E proposes that the utilities conduct an open season during which a CCA or prospective CCA would be required to commit to a specific load forecast identifying the load expected to be served by the CCA. The open season would be conducted before the utility buys power for that load and according to the utility's resource planning schedule. The objective would be to mitigate the possibility that both the utility and the CCA would be procuring power for the same group of customers. SDG&E proposes that the CCA assume liability for differences between its load forecast and actual demand (and presumably be credited in cases where the difference results in lower costs as well). The proposal presumes that the utility would act as provider-of-last resort in cases where the CCA did not have access to adequate power. If the Commission were to adopt this proposal in concept, SDG&E would provide more details about its operation in Phase 2.

CCSF, ORA, SCE, and TURN support this idea in concept. TURN suggests the utilities be permitted to impose penalties for a CCA's failure to meet its commitments with regard to the timing and demand forecasts of its operations. LA/CV believes an open season would be duplicative of long-term resource planning efforts. It also raises a concern that the CCA's failure to meet

its commitments may be due to the failure of the utility to perform services for which the CCA pays.

**Discussion.** We agree with the parties who advocate in favor of an open season as a way to promote sound resource planning by the utilities and the CCAs, and also facilitate operations. SDG&E's proposal for CCAs to assume the risks associated with forecasting errors is reasonable and similar to the balancing fees we have approved for gas transportation tariffs. Utility tariffs should include fees that bears a reasonable relationship to the costs the utilities will incur as a result of the suspension of the CCA's initial operations or schedule power on behalf of CCAs. We expect the utility tariffs to provide for the forgiveness of such penalties for CCA non-performance if the reason for that non-performance relates to a failure of the utility to meet its commitments to the CCA in any way, for example, with regard to connections, transfer of customer information, mailing of customer notices or any other operational activity.

We expect the utilities to act as "provider of last resort" consistent with their public utility obligations and in light of the protections and privileges they receive as regulated entities. This role may also be necessary to protect the operational integrity of the transmission system. Notwithstanding this utility obligation, we would expect the CCA to purchase and schedule delivery of spot market supplies or purchase balancing services from the ISO, obviating the need for utility involvement. In no case will we agree to investments designed to interrupt power to CCA customers in cases where the CCA does not have adequate resources and where the utility is able to deliver power. Instead, the CCA should expect to pay for backup power at spot market prices. We agree that customers should have the right to return to the utility, consistent with AB 117, and assume the costs of re-entry, as we discuss earlier.

## **F. Responsibility for CRS Liabilities**

LA/CV and CalCLERA raise the issue as to whether the CCA or its customers should be responsible for the CRS. Whether the CCA or its customer receives the bill and pays it, the customer will ultimately assume the cost. The issue is whether the CCA or the utility should determine cost allocation and the arrangements for payment if the CCA assumes liability for the payments. DWR, the utilities and bundled customers would be indifferent on this issue as long as the utility and DWR received the CRS revenues. SCE, however, believes these utility liabilities should be billed directly to customers so the Commission is certain that the way they are allocated is just and reasonable. DWR expresses concern that the assumption of this liability by a CCA may have some implications for its bond and power charge obligations.

**Discussion.** AB 117 requires the CRS charge to be imposed directly on the customer. Section 366(d)(e) and (f) refer to the obligations of “retail end-use customers” assuming the costs of the components of the CRS in “commission-approved rates.” Because of DWR’s expressed concern, we adopt the utilities’ proposals for billing customers directly for the CRS.

## **G. Collection of Amounts Relating to CRS Exemption for Baseline Customers**

Water Code Section 80110 provides that so long as DWR is recovering its energy procurement costs, the total rate for residential customers with usage below 130% of baseline amounts must remain at the same level as those rates in effect on February 1, 2001. This subsidy is referred to as the “Baseline Exemption.” Cost liabilities adopted since that time have been allocated to other customers. The resulting shortfall has been allocated in equal portions to residential, commercial and industrial customers. This subsidy program created by AB1X does not apply to CCAs, although they could voluntarily implement it

by structuring their energy cost recovery so that baseline customers do not pay the CRS. Bundled service customers, however, should not have to subsidize residential CCA customers. All parties agree this subsidy should be assumed by the CCA, not bundled customers.

Each utility proposes a different way to implement the subsidy for baseline customers. PG&E is concerned that this subsidy to low-usage customers would promote “cherry picking” of customers by CCAs. To ameliorate this possibility, PG&E would calculate each CCA’s CRS liability by estimating the composition of the CCA’s customer usage. SCE would calculate the total subsidy according to total CCA demand, bill the CCA the amount and permit CCAs discretion to fashion cost allocation in ways that offer baseline customers the same protections offered to utility bundled customers pursuant to AB1X. SDG&E describes its proposal as similar to SCE’s and would bill CCA customers for the CRS as a nonbypassable surcharge, and unbundle the same amount on its own bundled customer bills in order that no customer may escape liability for related costs.

LGCC and CCSF support SCE’s proposal. CCSF and SCE oppose PG&E’s proposal to impose the CRS according to the composition of a CCA’s customer base. CCSF believes this disparate treatment of CCAs on the basis of customer class characteristics would violate the prohibition on cost-shifting. SCE objects to SDG&E’s proposal on the basis that its objective to collect CRS revenues is more readily implemented without the need for another nonbypassable surcharge. SDG&E comments that PG&E’s proposal fails to recognize that the AB 1X requirement applies to CCAs as well as utilities and may violate AB1X for that reason.

**Discussion.** We understand that SDG&E and PG&E may be concerned about the possible impacts of inconsistent application of the baseline exemption between the CCA and the utility. Nevertheless, we believe SDG&E and PG&E's proposals are administratively complicated and adding another surcharge to customer bills may lead to customer confusion. We are also concerned that PG&E's proposal would allocate the CRS differently across CCAs. Because CCAs would be governmental agencies that are accountable to the public, they can be entrusted to design cost allocation according to the needs of their local communities and the types of liabilities they incur. We agree that SCE's proposal is reasonable from the standpoint of administrative simplicity and avoids cost-shifting. Accordingly, we herein direct all three utilities to calculate the CRS subsidy, and to bill the CCA as SCE proposes.

#### **H. Exclusion for Norton Air Force Base**

IVDA seeks an exemption for Norton AFB from the DWR cost component of the CRS in order to promote economic development at the air force base. It justifies its request for an exception on the basis that SCE did not include Norton's load in the demand forecast DWR relied upon when it purchased power that is subject to CRS treatment. IVDA argues its proposal is consistent with the "fair share" principle adopted in orders addressing similar issues for municipal departing load (D.03-07-028) and customer generation departing load (D.03-04-030). IVDA argues that granting an exclusion for Norton AFB is consistent with the prohibition against cost-shifting because DWR did not incur any power costs on behalf of Norton. IVDA believes the prohibition against cost-shifting should be applied consistently to permit a CCA or its customers to receive the benefit of that prohibition as well as assume the liabilities. LGCC supports IVDA's proposal for reasons similar to those put forth by IVDA.

The utilities oppose this exclusion on the basis that it require other CCA customers or utility customers to make up the difference in contravention of AB 117. PG&E argues the exclusion would be inconsistent with Commission policy on exclusion from DWR bond costs and that DWR forecast no CCA load prior to entering into subject contracts. SCE admonishes IVDA for seeking to capitalize on base closures and argues that IVDA is seeking an exclusion for more acreage than that which comprised Norton AFB.

**Discussion.** SCE's forecasts to DWR, and upon which DWR relied in signing purchased power contracts, assumed that Norton AFB would close and therefore demand no power during the periods in question. Since that time, IVDA plans to build out at the site.

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

The acreage which would apply in this case is not relevant. The exclusion would apply to the load removed from the SCE forecast. For all the forgoing reasons, we direct SCE to exclude IVDA from the DWR component of the CCA CRS for amounts equal to the reduction in demand included in SCE's forecast to DWR, which SCE states is 523 MWh or 120 kW capacity.

#### **I. CRS True-Up**

The utilities, DWR, and CCSF propose that the CRS be "trued-up" annually so that undercollections or overcollections are recognized in the subsequent year's CRS. These credits or debits, with interest, would be applied

equally to all CRS vintages. PG&E illustrates the risks of forecasting a CRS by observing that DWR estimates for PG&E for 2006 ranged from about \$21/MWh to about \$51/MWh, depending on market conditions.

CalCLERA and Local Power argue for a forecast CRS for which the utility would be liable. Local Power interprets AB 117 to require the Commission to set a CRS on the basis of a forecast and retain the CRS from year to year. Related to this, several parties proposed a cap on the CRS or a mechanism that would effectively cap the CRS. CCAs and prospective CCAs argue that the cap will provide much-needed certainty. Local Power appears to advocate that the utilities' shareholders should assume the risk associated with a cap. The utilities, ORA and TURN oppose a cap, arguing that a cost cap could cause unlawful cost-shifting or expose shareholders to risks AB 117 does not intend.

**Discussion.** AB 117 does not refer explicitly to a true-up of the difference between a forecasted CRS amount and actual CRS liabilities, which can only be precisely identified retrospectively. Local Power argues that the statute prohibits a true-up. It refers to Section 366.2(c)(7), which states that "After certification of receipt (from the CCA) of the implementation plan and any additional information requested (of the CCA), 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..." This language might suggest that the Commission would inform the CCA of a specific total dollar amount for energy contract liabilities.

However, other elements of the statute are clear that utility bundled customers must not have to pay for energy contract liabilities that were incurred on behalf of customers that are ultimately served by the CCA. This is the



provision referred to as the “prohibition against cost-shifting.” For example, Section 366.2 (c)(5) refers to developing a cost recovery mechanism that would “prevent shifting of costs.” Section 366.1(d)(1) states the Legislature’s intent “to prevent any shifting of recoverable costs between customers.” Section 366.2(f)(2) directs the Commission to set a CRS based on “costs attributable to the customer.” Here, the statute states a broad intent to prevent cost-shifting and subsequently refers to that intent clearly and explicitly in sections implementing the cost in question, namely, the CRS. Although the statute never refers to a true-up by any name, it assumes a true-up by implication: because a forecast of the CRS will never exactly match actual costs, setting the CRS according to a forecast that could not be trued-up would permit shifting costs between CCA customers and utility bundled customers. In contrast, the section that might imply a fixed and specific dollar liability is referred to obliquely in a section that describes a transaction between the Commission and the CCA, namely the Commission’s duty to “inform” the CCA of its cost liability following review of the CCA’s implementation plans and other information. In a case, such as here, where the statute might appear to present a conflict, we must look to the statute as a whole and follow that requirement that is articulated in the statements of Legislative intent and supported by explicit language in subsequent sections of the statute, and this practical and makes sense in the regulatory context.

We find that AB 117 requires that CCA customers pay the actual rather than forecasted costs that are components of the CRS. We agree with the utilities and consumer groups that the CRS should be trued up annually. An annual true-up is reasonable because it will mitigate the possibility of large swings in CRS levels that more accurately match costs with cost causation than true-ups over longer periods. Similarly, we do not adopt a CRS cap for CCAs. Whether

or not the idea is sound from a policy perspective, we believe AB 117 prohibits a rate recovery mechanism that might we might result in cost-shifting between customers and we would not put the utilities at risk for investments that are stranded for reasons they could not control or foresee.

The utilities should enter CRS costs and revenues into relevant balancing accounts, as they propose, which will be reconciled annually in proceedings addressing the CRS for direct access customers. At this time, the appropriate docket is R.02-01-011.

#### **J. CRS Implementation**

Having considered the general methodology and cost allocation treatment for the CRS, we must decide how to implement it. The utilities do not assume the Commission will adopt a number in this phase of the proceeding, preferring to address the issue again and in more detail in subsequent hearings. DWR presented illustrative CRS values but explicitly does not endorse any at this time. DWR offers to work with the utilities to develop final values after the Commission resolves outstanding issues about the CRS methodology and its application. Only one party proposed a specific CRS number for the Commission's consideration. CCSF proposed the Commission adopt a 1.5 cent CRS for a two-year period, which it estimated using DWR's methodology and forecast gas prices. CCSF originally referred to this number as a "cap" but clarifies its view that it should be subject to subsequent modification to reflect market conditions and power commitments, consistent with the utility proposals. CCSF argues that CCAs need some early indication of the level of the CRS for planning purposes.

PG&E argues that CCSF's CRS is substantially below those DWR presented using various market scenarios and was not proposed for SCE or

SDG&E. PG&E argues that this phase of the proceeding was not designed to develop an actual number for the CRS.

**Discussion.** We clarify first that one objective in Phase 1 of this proceeding is to quantify the costs of service and the CCA CRS. This objective should be clear on the basis of the parties' discussion at the prehearing conference with regard to the need to bifurcate the proceeding. Many stated a concern that their litigation of operational issues in this proceeding would be superfluous if the Commission were to set costs at levels that CCAs and prospective CCAs believed were too high to justify developing energy procurement programs. The scoping memo agreed to bifurcate the proceeding on the basis of that discussion. An ALJ ruling dated January 29, 2004 also stated the Commission's intent to develop a CRS in Phase 1.

The utilities' current proposal to delay adoption of a specific CRS amount until after Phase 2 would undermine the Commission's commitment to provide CCAs and prospective CCAs with some early indication of the costs they can expect to incur if they choose to procure energy. Agreeing to wait until after the resolution of Phase 2 issues could delay implementation of the CCA program until mid- or late-2005, almost three years after the enactment of AB 117.

Nor do we agree with the utilities that the record does not provide adequate information to adopt an interim CRS. In fact, we are not sure what the utilities would have the Commission explore in Phase 2 hearings on this issue since the parties agree to the DWR model and its components and this decision resolves related issues.

Adopting an initial CRS amount at this point would require a leap of faith but one that is reasonable considering the results of the DWR's modeling. DWR presented a sensitivity analysis that included illustrative ranges of CRS

amount that vary depending on assumptions about market conditions. DWR explains that components of the CRS related to the DWR bonds and historic utility stranded costs are fairly stable and do not depend much on market conditions. The more variable components of the model are the utility CTC and DWR power charge, which may vary considerably depending on market conditions such as gas prices, load growth, capacity additions, and reserve margins.

Importantly, DWR's analysis shows that the CRS may vary markedly from period to period, and is unlikely to be predictable or stable because of its sensitivity to changing market conditions. This understanding that minor changes in market conditions may have a pronounced effect on the CRS is disappointing from the standpoint of our effort to accommodate the CCA's need for some degree of certainty with regard to their CRS liabilities. On the other hand, it removes one of the arguments for delay, that is, that additional work in this area will provide a more accurate CRS. Additional precision in the modeling may be technically appealing but market conditions that are largely unpredictable and out of our control appear likely to have a more pronounced effect of the level of the CRS level than additional precision in the modeling.

For all the foregoing reasons, we find the record in this proceeding is adequate to adopt an initial CRS using the analysis presented by DWR and CCSF. To avoid further delay, we proceed to fashion an interim CRS that is based on available information and analysis and which may be modified immediately if final CRS calculations are substantially higher or lower than the one we adopt today. This charge, like all CCA CRS amounts, shall be subject to true-up based on actual DWR and utility liabilities.

DWR presented the following range of CRS levels in cents per kilowatt-hour for each of the three electric utilities for 2005 and 2006:

	<u>2005</u>	<u>2006</u>
<b>PG&amp;E</b>		
Range	1.60-2.99	1.00-3.99
Base case	2.28	2.59
<b>SCE</b>		
Range	1.75-3.40	.650-3.85
Base case	2.51	2.35
<b>SDG&amp;E</b>		
Range	2.24-3.34	1.03-3.71
Base case	2.60	2.18

CCSF's estimate of \$.015/kWh is on the low end of DWR's range because it applied higher gas prices using more recent market information which reduces CRS liabilities.

While we acknowledge that these estimates are not perfect, they nevertheless permit us to adopt a CRS today that may be tried up later, on the basis of the costing principles we adopt in this order. We will therefore establish a CRS today that may be modified either in 18 months or sooner in the event the utilities' final CRS estimates, using more recent forecasts, are at least 30% higher or lower than the adopted CRS. We set the first CRS at \$.022/kWh which lies well within the range of CRS estimates presented by DWR. Considering the trend of increasing gas prices, we believe it would be unreasonable to set a CRS at the lowest possible level. We wish to avoid a circumstance where a CCA relies on an artificially low CRS only to later have to make up the difference with a substantially higher charge. On the other hand, we do not want to set the CRS

too high and create a barrier to CCA development. We believe \$0.022/kWh achieves the appropriate balance.

Consistent with our previously-stated concerns that the CCA program move ahead in spite of slow progress to implement program elements, we direct the utilities to file an advice letter and related tariffs within 30 days of the effective date of this order that would set the initial CRS at \$.022/kWh, effective January 1, 2005. This amount will be trued-up and recalibrated in 18 months or when the utilities' forecast CRS is more than 30% higher or lower than \$.022/kWh. Thereafter, the CRS shall be trued-up every year and vintaged in related DWR revenue requirement proceedings, according to this order.

#### **V. Informational Needs of CCAs**

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

“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.”

D.03-07-034 has already directed the utilities to provide CCAs with certain information at no charge to the CCA. R.03-10-003 and the ALJ's November 26, 2004 ruling found that remaining issues regarding the provision of information to CCAs should be resolved in Phase 1 of this proceeding. Accordingly, the ALJ directed the utilities to meet with interested parties on these issues and to file a

report on the results of the meetings. The utilities held such meetings and on January 30, 2004, the utilities filed a Joint Utility Report on Community Choice Aggregation Information Issues which formed the basis for the debate on related issues.

In this area, the main issues addressed in this proceeding concern the kind of information the CCAs should be entitled to receive and the confidentiality of customer information.

The information the CCAs may need from the utilities may be confidential, for example, (1) basic load and usage data required to estimate energy procurement needs and (2) customer information needed to contact customers and provide services, including name, address, and meter information. A major dispute is over whether the type and nature of information should differ before and after the CCA initiates service and the customer is officially transferred to the CCA.

The utilities raise general concerns that they not be required to provide confidential information to CCAs except with strict protections for utility customers. SDG&E argues that CCAs must have the written consent of the customer, prior to the customer transferring to the CCA, in order to receive such information, which is current practice for utility release of customer information. Prior to customer cut-over, the utilities agree to provide information on customer load and usage if it is aggregated in order to mitigate confidentiality concerns. SDG&E argues that CCAs would not need more since, as cities and counties, they would have information about local customers. PG&E proposes to aggregate customer information until the customer is transferred to the CCA and then release all customer information to the CCA. It would continue to offer basic information required by D.03-07-034 at no charge to the CCA and provide a

standardized list of information to the CCA at cost. It asks the Commission to approve tariff provisions that would have the CCAs indemnify the utilities from liabilities that might occur from the release of customer information.

ORA generally agrees with the utilities' proposals and suggests that customer notification letters be drafted by the CCAs but mailed by utilities to accommodate confidentiality concerns that arise before cut-over to the CCA. ORA shares the utilities' concerns that load data remain aggregated and argues that CCAs do not need more in order to forecast load. In response to CCA concerns that they cannot market services without specific customer load data, ORA agrees with SDG&E and PG&E that cities and counties have access to tax rolls that they may use to contact individual customers.

LGCC objects to the many rules the utilities would implement to limit the amount of information LGCC argues is required for CCAs to market and provide energy services. LGCC, for example, objects to the utilities' proposed requirement that a CCA provide projected load forecasts to the utilities, and assume the risk that the forecast is accurate, while simultaneously proposing to deny the CCAs access to load information that it could not otherwise obtain. It argues that aggregated load data would not provide enough information for CCAs to conduct meaningful marketing and load forecasting. LGCC believes customer confidentiality would not be compromised if the individual load data was masked so that it did not identify the customers. ElectricAmerica goes into some detail about the kinds of information CCAs may need, most of which would be included in existing utility data bases.

Local Power believes the statute is clear with regard to its requirement that utilities provide all relevant information to CCAs that are "investigating, pursuing or implementing" CCA programs and suggests that confidentiality



concerns may be addressed by imposing limits on the CCA's use of the information it gets.

LA/CV contends that customers have implicitly agreed to the release of their information when their duly elected public representatives form the CCA. LA/CV believes the CCA is a consortium of customers, as distinguished from the direct access program, where customers must affirmatively choose to change their service provider rather than opt-out of service offered by the CCA. LA/CV and Local Power also observe that AB 117 requires the CCA to notify utility customers of the CCA's plan to offer service, a requirement the CCA cannot satisfy without customer billing information.

The utilities assert that they should only be required to provide information that is directly relevant to the CCA's energy operations. LGCC suggest that the information requirements adopted in D.03-07-034 on behalf of CCAs is the minimum necessary for prospective CCAs but suggests the utilities have not been cooperative with prospective CCAs in working on their other information needs.

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

information as long as they are investigating, pursuing or implementing a CCA program.

Section 366.2(c)(13) (A) supports this finding in its requirement that CCAs provide opt-out notifications to prospective customers prior to cut-over.

Although Section 366(2) (13)(B) gives the CCAs the *option* to request utility assistance with the notifications, each CCA must assume ultimate responsibility for the notices. The CCA cannot satisfy this responsibility without access to customer names and addresses. Thus, if the Legislature had intended for customer information to remain with the utility, it would have not required the CCA to issue the opt-out notices.

SDG&E argues that D.01-07-032 and D.90-12-121 should apply in this case. Those orders prohibit a utility from disclosing customer information even to a district attorney without either the customer's consent or the order of a judge. The facts in that case, however, are distinguishable from those here, primarily because the statute itself directs the provision of customer information to a CCA. Moreover, unlike a district attorney investigating criminal activity. The statute permits the CCA to receive such information. Unlike the unwilling subject of a criminal investigation, the customers for whom the CCA seeks information have implicitly agreed to permit the CCA to aggregate their energy requirements and offer service.

We believe AB 117 assumes, as we do, that CCAs can be entrusted with confidential customer information. Unlike energy service providers offering direct access, CCAs are government agencies. As long as some basic protections are in place, the risks of providing confidential information to these entities is outweighed by the dictates of the statute and the potential benefits CCA customers would realize only if CCAs have the information they need to make

fully informed decisions regarding energy procurement, service requirements and resource planning decisions.

In addition to its requirement that utilities provide information to CCAs before and after they initiate operations, AB 117 specifies the types of information the utilities must provide to CCAs. Section 366. 2(c)(9) refers to “appropriate billing and electrical load data, including, but not limited to, data detailing electricity needs and patterns of usage.” The statute specifically refers to “billing” data as distinct from “electrical load data.” We are not aware how aggregated or masked billing data could satisfy the statutory requirement. Again, the plain language of the law means that the CCA is entitled to any and all billing data that is reasonably useful to the CCA. It also refers to information “detailing” electricity needs and patterns of usage. Use of such specific terms reflect the Legislature’s intent for CCAs to have information that is neither masked nor aggregated, to the extent such information is required by CCAs that would reasonably “investigate, pursue or implement” a CCA program.

This approach is consistent with our understanding that CCAs may need specific usage information in order to market their services and tailor those services to customer needs. We are not convinced by utility testimony that city and county tax rolls will provide the kind of information CCAs need to accomplish those ends.

We direct the utilities to provide all relevant usage information, load data and customer information to CCAs. The CCA shall sign nondisclosure agreements for any confidential information that is not masked or aggregated. We will also require that all notices relevant to CCA programs inform customers that the utility may share customer information with the CCA and that the CCA

may not use the utility's information for any purpose other than to facilitate provision of energy services.

We agree with PG&E and SDG&E that the utilities should be permitted to include language in their tariffs that CCA indemnification of the utility from liability associated with release of customer information, as long as the utility provided the information responsibly and according to Commission rules, orders and approved tariffs. Utilities should inform customers who complain about the release of customer information that California state law requires the release of that information to CCAs.

Finally, we state our intent to enforce the law with respect to its requirement that the utilities "cooperate" with CCAs in the provision of all relevant information, a term which we interpret broadly. The utilities may not determine what information is "relevant" to CCA operations as long as the utility is reimbursed for the reasonable costs of providing the information. While we welcome the utilities' tariff proposals for the secure and cost-effective sharing of information, we will not tolerate utility actions or delays that may affect the provision of information to CCAs or CCA services to customers.

## **VI. Other Issues and Terms of Service**

### **A. CCA Program Phase-In**

LGCC, CCSF and other prospective CCAs suggest that a CCA should be able to phase in their programs, that is, offer service to some customers or customer classes before others. PG&E supports this concept to a limited extent as long as it does not lead to cost-shifting. SCE and SDG&E propose that the CCAs cut-over all customers concurrently to avoid the administrative costs of phasing and to avoid "cherry picking" of most valuable customers and thereby undermine those portions of AB 117 that refer to universal service and equitable

treatment of customers. PG&E proposes to permit phasing, as long as the cut-over is accomplished within six months, in order to ease the administrative burdens of the transfer.

**Discussion.** AB 117 does not prohibit a phase-in of the CCA's program or customer cut-overs. In advocating for a prohibition on a phase-in, SCE relies on Section 366.2(c)(4)(A)(B) which directs CCAs to develop an implementation plan that "shall provide for...universal service" and "equitable treatment of all customers." SCE appears to argue that these terms require that all customers be treated equally in all respects. We do not agree that this is what the statute requires. The terms are not defined or discussed in any other portion of the statute and, alone, are so broad that they are subject to considerable interpretation. Indeed, "universal service" and "equitable treatment" are concepts that have been subjects of debate and policy decisions in numerous Commission dockets over the years. Without more guidance from the statute, we cannot assume these terms preclude a phase-in.

However, we need not delve further into statutory interpretation on this issue. Rather, we leave the matter to the CCAs. We note that a pilot program may facilitate a CCA's program implementation in some respects by, for example, allowing it to develop its administrative structure incrementally or to purchase power supplies in specified quantities. Thus, the barrier to a pilot program or phase-in would not be the law but the possible additional costs of administering the cut-over of customers from the utilities to the CCAs that might occur, for example, as a result of differing load profiles and shifting procurement requirements, as ORA suggests. PG&E proposes a limited phase-in that might actually mitigate costs. We direct the utilities to propose tariffs that offer a phase-in at rates and charges that would recover such costs, consistent with other

portions of this order addressing implementation and transaction costs. Their tariffs should permit the utilities to negotiate with the CCA to phase-in the CCA's program in ways that promote cost-savings, as PG&E suggests, and the associated cost savings should be reflected in the negotiated outcomes.

### **B. CCA Requirements to Offer Service**

LA/CV and other CCAs believe CCAs should be permitted to offer service to a portion of local customers. The utilities argue that AB 117 requires CCAs to offer service to all customers.

Section 366.2(b) requires the CCA to “offer the opportunity to purchase electricity to all *residential* customers within its jurisdiction.” (Emphasis added.) A general rule of statutory construction provides that where the language of a statute is specific, all other things not specified are excluded from the application of the rule unless other terms of the statute clarify or conflict with the rule. Here, the statute requires service offering to all residential customers and does not mention a similar requirement for commercial or industrial customers. The reference to residential customers does not conflict with any other provision of the statute. We therefore find that AB 117 does not prohibit the CCA from offering service to a portion of customers in its territory, with the exception that it must offer service to all residential customers. As long as the utilities' tariffs reflect the costs of serving the CCA and the requirements of the utilities' tasks are reasonable and otherwise lawful, this Commission is indifferent to whether a CCA offers service to a portion of the community or all of it.

### **C. CCA-Specific Load Profiles**

Some parties propose that the Commission use load profiles specific to individual CCAs in computing the CRS and for scheduling and settlements with the California ISO. CCSF observes that CCAs would have differing load profiles

according to regional climate and economy. LA/CV proposes a relatively easy way to develop load profiles that may be useful for various purposes.

The utilities oppose this on the basis that the ISO still uses system average load profiles. If the Commission were to permit some but not all CCAs use specific load profiles, the utilities would realize a revenue shortfall which would have to be passed along to other ratepayers in contravention of the AB 117 ban on cost-shifting. The utilities also raise concerns that they do not have the data bases for creating CCA-specific load profiles and creating them could be expensive.

**Discussion.** We agree with the utilities that adopting CCA-specific load profiles would be costly and likely lead to cost-shifting. Even if we were to apply CCA-specific load profiles to all CCAs, cost shifting could occur if the bulk of CCAs had favorable load profiles compared to the average of the utilities' systems. While load profiling may make sense conceptually, the effects of its implementation under the current circumstances are unknown and potentially harmful to utility bundled customers. We may reconsider this proposal if the Commission or the FERC eventually unbundle utility systems by region.

Load profiles may be useful to CCAs for other purposes. The utilities believe they may be difficult and costly to develop, although SDG&E addressed a simplified method for developing a load profile that would adjust the system average according to local usage and climate. The utilities' tariffs may offer at cost the development of CCA-specific load profiles or a modified approach based on the system average.

#### **D. Boundary Metering**

Local Power suggested that the Commission order the utilities to install an additional CCA meter at every point at which a meter installed by the utility

currently exists. SCE maintains concerns that this proposal is expensive and impractical, although it suggests considering the matter one case at a time. PG&E and SDG&E would also support boundary metering if it were offered on a time and materials basis.

**Discussion.** Section 366.2(c)(18) provides that “at 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 choice aggregator’s political boundaries.” Again, we read the plain language of this section and, as the utilities suggest, require that they include an option in their tariffs for boundary metering that would be provided at the cost of time and materials.

#### **VII. Comments on Proposed Decision**

The proposed decision of ALJ Malcolm in this matter was mailed to the parties in accordance with Pub. Util. Code § 311(d) and Rule 77.1 of the Commission’s Rules of Practice and Procedure. Comments were filed on \_\_\_\_\_ and replies were filed on \_\_\_\_\_.

#### **VIII. Assignment of Proceeding**

Michael R. Peevey is the Assigned Commissioner and Kim Malcolm is the assigned ALJ in this proceeding.

#### **Findings of Fact**

1. Allocating implementation costs to ratepayers that are related to the development of the CCA program’s infrastructure would be fair, relatively simple to administer and avoid the barriers to entry that might occur if a handful of individual CCAs were required to assume those costs.
2. Implementation costs that are attributable to individual CCAs should be charged to those CCAs in tariffs according to the costs of time and materials.



3. The utilities' incremental costing methodologies for CCA transaction costs are reasonable to the extent the utilities do not recover transaction costs twice.

4. Utilities are currently recovering the costs of certain transaction services to CCAs. Permitting the utilities to charge for those services to CCAs prior to a general rate case would permit the utilities to recover related costs twice to the extent the utilities do not incur incremental costs for those services.

5. Tracking revenues from CCA transaction services in an account for "other revenues" would not eliminate the prospect of double recovery because such an account does not provide for refunds for past paid costs; such accounts are considered in general rate cases for forecasted costs and revenues.

6. Approving balancing accounts for implementation costs is reasonable prior to a general rate case to assure the utilities recover reasonable implementation costs.

7. Approving permanent balancing account treatment for implementation and transaction costs would undermine utility incentives for cost containment and is contrary to the Commission's regulatory treatment of customer and operational costs generally. Forward-looking charges will provide certainty for CCAs and provide the utilities a reasonable opportunity to recover their costs.

8. The utilities did not propose final charges in this phase of the proceeding.

9. Delaying the effectiveness of CCA tariffs until after the close of Phase 2 in this proceeding would unreasonably delay the implementation of the CCA program.

10. Direct access tariffs provide a reasonable proxy for interim CCA tariffs until the Commission has approved final CCA tariffs.

11. The utilities are likely to incur incremental billing costs when they serve CCAs.

12. If CCA fees for processing utility bills are not unbundled, CCAs may be liable for costs related to utility customer services, rather than those incurred for CCA customers.

13. The utilities did not demonstrate that CCA customers will make more calls to the utility than they made as utility bundled customers.

14. Developing the infrastructure for opt-out procedures is an implementation cost attributable to the CCA program generally.

15. Re-entry fees are those that reflect the cost of transferring a CCA customer back to the utility as a bundled service customer. The re-entry of large customers in particular may cause the utility to incur high procurement costs.

16. The utilities' "Detailed Processes" outlines provide information about how they propose to implement various operations and services for CCAs. These outlines form a reasonable foundation for resolving Phase 1 issues except as provided herein.

17. The Commission has adopted a CRS for certain types of customers in other proceedings.

18. DWR's methodology for developing the CRS reasonably reflects the energy liabilities that should be charged to CCAs, and would appropriately exclude avoidable costs, reflect DWR and utility bond or contract refunds or credits, and apply to new as well as existing customers. No party opposes DWR's methodology for estimating related costs.

19. "Vintaging" would track the costs that are attributable to an individual CCA's customers depending on the timing of the CCA initiating operations, and reflects the changing liabilities of the utilities and DWR.

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

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

21. Unbundling the components of the CRS may provide customers and CCAs with valuable information about the costs of their services.

22. Power from some utility or DWR energy purchase contracts may be allocated to CCAs or otherwise permit the purchase of power by CCAs, who would be paying the costs of those contracts by way of the CRS.

23. Permitting CCAs to take delivery of power related to CRS liabilities may reduce California consumers’ energy bills and promote the interests of the state and its economy.

24. An “open season,” as SDG&E describes it, would help the utilities and CCAs plan for CCA operations in a way that may permit more efficient and effective resource planning.

25. CCAs should purchase and pay for real-time power deliveries and balancing services where their power supplies are not adequate.

26. The demand forecasts relied upon by DWR for purchasing power during the energy crisis assumed the installation of distributed generation in California.

27. The exemption from the CRS for baseline usage required by Water Code Section 80110 represents a subsidy that must be recovered from the CCAs or their customers.

28. SCE’s proposal to bill the CCA directly for the baseline subsidy amount is administratively simple and avoids the customer confusion of an additional nonbypassable surcharge.

29. SCE’s demand forecasts provided to DWR, and upon which DWR relied in purchasing long-term power, assumed load reductions at Norton Air Force Base in anticipation of the base’s closing.

30. The utilities would overcollect or undercollect CCA CRS costs if they were not permitted to true-up in some fashion the difference between the forecasted CCA CRS rate and the actual CCA CRS liabilities, which can only be precisely specified after the fact. Similarly, a cost cap may permit a circumstance whereby the utilities might not be able to recover all CCA CRS costs, as mandated by AB 117.

31. Requiring utility bundled customers to assume liability for the CCA CRS forecast being equal to or more than actual CCA CRS liabilities would represent cost-shifting between utility bundled customers and CCA customers.

32. The Commission has always intended to set cost recovery for CCA services and the CCA CRS in Phase 1 of this proceeding.

33. Delaying the implementation of CCA costs until after the resolution of Phase 2 of this proceeding could delay implementation of the CCA program until almost three years after passage of AB 117.

34. The record in this proceeding does not permit the Commission to approve final rates and cost recovery amounts for CCA services that would be the subject of tariffs.

35. The utilities' tariffs that govern services to direct access customers address services and operations that are substantially similar to those needed by CCAs. They are reasonable proxies for the costs the utilities would incur in serving CCAs while the Commission reviews proposals for final CCA rates and tariffs.

36. DWR's model suggests that minor changes in market conditions could cause substantial variations in the CRS. For that reason, developing more precise specifications for the DWR model may not necessarily significantly improve the reliability of the CRS.

37. The record in this proceeding provides enough information about likely CCA CRS liabilities to set an interim CCA CRS in the amount of \$.022/kWh, subject to true-up.

38. Permanent balancing accounts may undermine incentives for economizing.

39. Utility forecasts of the costs of CCA program implementation and transactions in general rate cases would promote certainty and cost management.

40. CCAs would “investigate or pursue” CCA programs prior to offering service and a CCA would need relevant customer and load data in order to conduct a meaningful investigation of CCA programs.

41. A CCA cannot notify customers of its intent to offer electrical service if it does not have access to relevant customer information.

42. In the CCA’s effort to satisfy customer notice requirements, tax rolls are not a reasonable substitute for customer information held by utilities partly because property owners would not necessarily be a utility customer of record.

43. Nondisclosure agreements would provide reasonable protections against the disclosure by a CCA of a utility’s customer information.

44. CCAs may need specific customer information in order to market energy services and tailor those services to individual customers or groups of customers.

45. CCAs need load data in order to develop cost-effective and reliable energy procurement strategies.

46. Customers would benefit from notification that contact information and usage data may be shared with the CCA and may not be disclosed to others.

47. A CCA phase-in or pilot program may facilitate the transfer of energy services from the utility to the CCA but may be costly.

48. Applying CCA-specific load profiles to ISO charges could increase liabilities to other customers.

49. Although developing CCA-specific load profiles may be costly, there may be simple ways to estimate them.

50. Boundary metering would help CCA develop area load profiles.

### **Conclusions of Law**

1. AB 117 provides the Commission discretion to determine which implementation costs should be allocated to individual CCAs and which of those costs should be allocated to ratepayers generally.

2. AB 117 defines transaction costs as those relating to metering, billing, and other customer services that are attributable to a single CCA.

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

4. The utilities should be ordered to charge CCAs for transaction costs in tariffs that include charges based on incremental costs.

5. The utilities should not be permitted to “true-up” transaction costs included in tariffs but should be permitted to forecast those costs in general rate cases.

6. The utilities should be ordered to apply direct access tariffs for CCA transactions until the Commission has approved final CCA tariffs in this proceeding.

7. The utilities should be ordered to propose final tariffs for recovery of transactions costs from ratepayers within 30 days of the effective date of this order for consideration in Phase 2 of this proceeding.

8. CCA tariffs should unbundle elements of the billing and call center services tariffs so that CCAs are not charged for billing processes and customers services that are unrelated to CCA services and CCA customer billings.

9. AB 117 requires CCAs to pay for “opt-out” notifications mailed by the utilities to customers. The utilities should charge for these services in the CCA tariffs.

10. The costs of developing the initial “opt-out” procedures should be assumed by all ratepayers as an implementation cost.

11. The utilities should be authorized to charge customers a re-entry fee after those customers have transferred from the CCA to the utility as a bundled customer. Large customers should pay for the incremental costs the utilities incur for procuring additional energy.

12. The utilities should establish a CRS, consistent with this order and DWR’s model, to allow the utilities to recover costs of power purchase commitments that become stranded as a result of the CCA initiating service. Such costs include DWR bond and power purchase contracts, utility power purchase commitments and balances in power purchase accounts but should not include costs that may have been avoidable or are not otherwise attributable to the CCA’s customers.

13. The utilities should be ordered to provide information about the components of the CRS and to provide a tariffed service to CCAs that would unbundle the components of the CRS on customer bills.

14. The utilities should be ordered to facilitate the allocation of power from DWR contracts and delivery of related power supplies to CCAs where a CCA requests.

15. Utilities should not be required to assume the risks of CCA forecasting errors or non-performance, and should propose tariff fees that reflect the cost of forecasting errors or non-performance attributable to the CCA.

16. The utilities should be required to act as provider of last resort where CCA power supplies are inadequate or where CCA customers seek to return to the utility as a bundled customer.

17. The utilities should not be permitted to interrupt power to CCA customers except consistent with the Commission-approved schedules. The cost of utility services that are provider in the utility's role as provider of last resort should be included in tariffs and reimbursed by the CCAs and their customers.

18. AB 117 requires that retail end-use customers of CCAs to pay for the CRS.

19. The utilities should charge CCA customers directly for the CRS.

20. The utilities should charge the CCA the baseline subsidy which they should calculate on a cents per kWh basis, according to the total CCA customer demand for each billing period, consistent with SCE's proposal.

21. SCE should exempt Norton Air Force Base from the CRS in amounts equal to the reductions it included in its forecasts to DWR and upon which DWR relied for long-term power purchases.

22. AB 117 does not permit cost-shifting of CCA CRS liabilities between utility bundled customers and CCA customers.

23. When read in conjunction with other provisions of AB 117, the requirement in Section 366.2(c)(7) that the Commission "inform" the CCA of its CRS liabilities is not a requirement that the CRS be capped or that utilities or utility bundled customers assume the risk for undercollections of CRS cost liabilities.



24. The utilities should establish balancing accounts for CRS costs and revenues and reconcile actual costs and revenues in the proceedings addressing the CRS for direct access customers, unless the Commission directs review of these costs and revenues in a different proceeding.

25. The utilities should not be required to assume the risk for CRS forecasts where CRS liabilities were reasonably incurred.

26. In the interim, the utilities should be ordered to apply the rates and cost recovery provisions of direct access tariffs to CCAs that begin operations prior to the Commission's approval of final CCA tariffs.

27. The utilities should file tariffs that implement an interim CRS of \$.022/kWh, subject to true-up in 18 months or when the final CRS forecast is 30% higher or lower than this amount.

28. The utilities should be permitted to establish balancing accounts to track the costs of developing the infrastructure needed to implement the CCA program, and should allocate those costs to all ratepayers, as set forth herein. These balancing accounts should be eliminated following each utility's subsequent general rate case.

29. The utilities should be required to provide forecasts of CCA implementation costs in their general rate cases for recovery from all ratepayers.

30. The utilities should develop tariffs for services to CCAs that include charges based on the incremental costs of each service but shall not charge CCAs for services for which the utilities already recover costs in their revenue requirements, consistent with this order. The utilities should modify their CCA tariffs in general rate cases, consistent with the regulatory convention for adjustments to revenue requirements for other customers. In their general rate cases, the utilities may propose charges to CCA for transactions services that are

currently included in utility revenue requirements and in such cases should propose offsetting reductions to other rates.

31. Section 366.2(c)(9) requires the utilities to provide all relevant information required by CCAs to “investigate, pursue or implement” meaningful programs. This requirement does not permit the utilities to deny CCAs access to relevant customer or load information.

32. Section 366.2(c)(13)(A) requires CCAs to provide customer notice of their intent to provide service, a requirement a CCA cannot satisfy without relevant customer information. Read in conjunction with Section 366.2(c)(9), this requirement presumes that the CCA will have access to certain customer information held by the utility.

33. Section 366.2(c)(9) requires the provision of detailed billing and load data to CCAs that are investigating, pursuing or implementing CCA programs.

34. The utilities should require CCAs to sign nondisclosure agreements when they share confidential information about customers or electricity load.

35. Notices to prospective CCA customers should inform customers that the utility may share customer information with the CCA and that the information may not be used for any purpose other than to facilitate the provision of energy services to the customer by the CCA.

36. Utility tariffs should provide that CCA indemnify utilities from liability for the disclosure of confidential customer information in cases where the utility has taken all reasonable precautions to prevent that disclosure.

37. AB 117 does not prohibit a phase-in or pilot program by the CCA.

38. Utility tariffs should offer a phase-in of a CCA program at cost.

39. The Commission will not determine which customers CCA should serve.

40. Utility tariffs should offer to develop an estimation of a CCA's load profile at cost, consistent with the proposal by SDG&E to adjust the system average load profile by use and climate.

41. Section 366.2(c)(18) requires the utilities to offer boundary metering. Utility tariffs should include an option for boundary metering to be provided at cost.

42. The utilities are appropriately providers of last resort, consistent with their utility obligations and the protections and privileges they receive as regulated public utilities.

## **O R D E R**

### **IT IS ORDERED** that:

1. Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) shall create balancing accounts for implementation costs incurred prior to cost recovery changes authorized in their respective general rate cases. The utilities shall not enter costs into those accounts after those changes become effective.

2. PG&E, SDG&E, and SCE shall, within 30 days of the effective date of this decision, file tariffs that are substantively identical to those in effect for direct access customers and which shall apply in the interim to Community Choice Aggregators (CCAs) prior to the Commission's approval of final CCA tariffs.

3. PG&E, SDG&E, and SCE shall, no later than 30 days after the effective date of this order, serve tariffs on all parties to this proceeding regarding costs and terms of services for CCAs. Cost recovery proposed in those tariffs shall be based on incremental costs but the tariffs shall not include charges for services for which the utilities already receive remuneration in existing revenue

requirements, consistent with this order. These draft tariffs will be considered in Phase 2 of this proceeding.

4. PG&E, SDG&E, and SCE shall, in their respective general rate cases, propose (1) a revenue requirement for CCA implementation costs and (2) changes to CCA tariffs for transactions including metering, billing, customer services and other services, which shall be authorized in the general rate case and remain in effect until a subsequent general rate case order, consistent with this order.

5. PG&E, SDG&E, and SCE's proposed tariffs shall include (1) unbundled elements for billing and call center services tariffs in ways that assure CCAs are not charged for billing processes or customer services that are unrelated to CCA services and CCA customer billings, (2) an optional service to produce and mail opt-out notices to customers at cost, (3) a re-entry fee for customers who transfer from the CCA to the utility and which reflects the cost of procurement for customers that are large enough to individually affect procurement costs, (4) an interim cost recovery surcharge (CRS) set at \$.022/kilowatt hour (kWh) and applying the terms and conditions set forth in this order, and which is subject to modification within the subsequent 18 months only if and when the CRS forecast is at least 30% lower than or higher than \$.022/kWh; (5) an option to unbundle components of the CRS on customer bills, at cost; (6) provisions that would protect the utilities from assuming the risk of CCA forecasting errors or nonperformance at cost; (7) a service to provide back-up energy supplies and balancing services at cost, but which does not permit service interruptions; (8) an offer to explore the allocation of power from DWR contracts and the delivery of related power supplies to CCAs at the CCA's request, and which shall not require the CCA to assume liability for power deliveries at levels exceeding those

subject to CRS charges; (9) a provision to charge CCA customers directly for CRS liabilities; (10) a charge to the CCA for the baseline subsidy on a cents per kilowatt-hour basis, consistent with this order; (11) the establishment of a balancing account for CRS costs and revenues that shall be subject to reconciliation in Commission proceedings reviewing the Department of Water Resources (DWR) revenue requirement or other proceeding, as the Commission may direct; (12) the offer to provide access to all relevant customer information, billing information, usage and load information, which shall be provided to the CCA at cost except that those information services already approved in D.03-07-034 shall be provided at no cost to the CCA; (13) a requirement that all confidential utility information shall be provided subject to nondisclosure agreement; (14) a requirement that customer notifications about prospective CCA operations inform the customer that customer information may be provided to the CCA subject to nondisclosure for any purpose other than those related to facilitating the CCA's services; (15) a provision for CCAs to indemnify the utilities from liabilities associated with the CCA's disclosure of confidential customer information where the utility has taken all reasonable steps to prevent such disclosure; (16) an option to phase-in a CCA's program at the incremental cost of that option; and (17) an option to have the utility install meters at CCA boundaries, at cost.

6. SCE's proposed tariffs shall provide an exclusion from the CRS for Norton Air Force Base in amounts equal to the reduction it included in its forecasts to DWR and upon which DWR relied for long-term power purchases, consistent with this order.

7. PG&E, SCE, and SDG&E shall, within 30 days of the effective date of this order, develop a forecast for the CRS in their respective territories, consistent

with this order, and serve a notice of availability of the forecast and work papers on all parties to this proceeding. Each cost components of the CRS shall be calculated and identified separately. Elements of the work papers that are confidential shall be provided subject to a standard nondisclosure agreement.

8. This proceeding remains open for the Commission's consideration in Phase 2 of final cost allocation and terms of services to CCAs and related issues as set forth herein.

9. This order is effective today.

Dated \_\_\_\_\_, at San Francisco, California.

**APPENDIX A**  
**LIST OF APPEARANCES**

## APPENDIX A

## Page 1

## \*\*\*\*\* APPEARANCES \*\*\*\*\*

Colin M. Long  
 A PROFESSIONAL CORPORATION  
 201 SOUTH LAKE AVENUE, SUITE 400  
 PASADENA CA 91101  
 (626) 683-9395  
 cmlong@earthlink.net  
 For: California Clear Energy Resources Authority (Cal-CLERA)

Matthew Gorman  
 ALVAREZ-GLASMAN & COLVIN  
 100 N. BARRANCA AVE., SUITE 1050  
 WEST COVINA CA 91791  
 (626) 858-9121  
 mgorman@agclawfirm.com  
 For: Cities in Southern California

David J. Coyle  
 ANZA ELECTRIC COOPERATIVE, INC  
 PO BOX 391090  
 ANZA CA 92539-1909

Gerald Lahr  
 ASSOCIATION OF BAY AREA GOVERNMENTS  
 PO BOX 2050  
 OAKLAND CA 94604-2050  
 (510) 464-7908  
 jerryl@abag.ca.gov  
 For: Association of Bay Area Governments

Barbara R. Barkovich  
 BARKOVICH AND YAP, INC.  
 31 EUCALYPTUS LANE  
 SAN RAFAEL CA 94901  
 (415) 457-5537  
 brbarkovich@earthlink.net  
 For: City & County of San Francisco

Reed V. Schmidt  
 BARTLE WELLS ASSOCIATES  
 1889 ALCATRAZ AVENUE  
 BERKELEY CA 94703  
 (510) 653-3399 X 111  
 rschmidt@bartlewells.com  
 For: California City-County Street Light Association (CAL-SLA)

Kevin Smith  
 BRAUN & BLAISING, P.C.  
 915 L ST STE. 1460  
 SACRAMENTO CA 95814  
 (916) 326-5814  
 smith@braunlegal.com  
 For: California Municipal Utilities Association

Scott Blaising  
 C. ANTHONY BRUAN, BRUCE MCLAUGHLIN  
 BRAUN & BLAISING, P.C.  
 915 L. STREET, SUITE 1420  
 SACRAMENTO CA 95814  
 (916) 682-9702  
 blaising@braunlegl.com  
 For: Inland Valley Development Agency

Jason Reiger  
 Attorney At Law  
 CALIFORNIA PUBLIC UTILITIES COMMISSION  
 LEGAL DIVISION  
 505 VAN NESS AVENUE  
 SAN FRANCISCO CA 94102  
 (415) 355-5596  
 jzr@cpuc.ca.gov  
 For: ORA

Jack Pigott  
 Director Of Renewable Affairs  
 CALPINE CORPORATION  
 WESTERN REGIONAL OFFICE  
 4160 DUBLIN BLVD.  
 DUBLIN CA 94568  
 (925) 479-6646  
 jackp@calpine.com  
 For: CALPINE CORPORATION

Joseph Peter Como  
 CITY AND COUNTY OF SAN FRANCISCO  
 CITY HALL, ROOM 234  
 1 DR. CARLTON B. GOODLETT PLACE, RM. 234  
 SAN FRANCISCO CA 94102  
 (415) 554-4637  
 joe.como@sfgov.org

Jim Stone  
 CITY OF MANTECA DEPARTMENT OF PUBLIC WOR  
 1001 WEST CENTER STREET  
 MANTECA CA 95337  
 (209) 825-2592  
 jstone@ci.manteca.ca.us  
 For: The City of Manteca

Scott Wentworth, P.E.  
 Energy Engineer  
 CITY OF OAKLAND  
 7101 EDGEWATER DRIVE  
 OAKLAND CA 94621  
 (510) 615-5421  
 swentworth@oaklandnet.com



APPENDIX A

Page 2

Matthew Gorman  
City Attorney'S Office  
CITY OF POMONA  
500 S. GAREY AVE. BOX 660  
POMONA CA 91769  
(909) 620-2071  
matt\_gorman@ci.pomona.ca.us  
For: City of Pomona

Susan Munves  
CITY OF SANTA MONICA  
1918 MAIN STREET  
SANTA MONICA CA 90405  
(310) 458-8229  
susan-munves@santa-monica.org  
For: City of Santa Monica

David R. Hammer  
Couty Counsel  
COUNTY OF TRINITY  
PO BOX 1428  
WEAVERVILLE CA 96093-1428  
(530) 623-8367  
dhammer@trinitycounty.org  
For: CITY OF TRINITY

Lindsey How-Downing  
Attorney At Law  
DAVIS WRIGHT TREMAINE LLP  
ONE EMBARCADERO CENTER, SUITE 600  
SAN FRANCISCO CA 94111-3834  
(415) 276-6500  
lindseyhowdowning@dwt.com  
For: Calpine Corporation

Michael G. Nelson  
Attorney At Law  
ELECTRIC AMERICA  
15901 REDHILL AVENUE, SUITE 100  
TUSTIN CA 92780  
(714) 259-2593  
mnelson@electric.com  
For: Electric America

Lynn Haug  
Attorney At Law  
ELLISON, SCHNEIDER & HARRIS, LLP  
2015 H STREET  
SACRAMENTO CA 95814-3109  
(916) 447-2166  
lmh@eslawfirm.com  
For: East Bay Municipal Utility District (EBMUD) Dept. Gen.  
Services (DGS)

Dian M. Grueneich  
Attorney At Law  
GRUENEICH RESOURCE ADVOCATES  
582 MARKET STREET, SUITE 1020  
SAN FRANCISCO CA 94104  
(415) 834-2300  
dgrueneich@gralegal.com  
For: City of Santa Monica

Jody London  
GRUENEICH RESOURCE ADVOCATES  
582 MARKET STREET, SUITE 1020  
SAN FRANCISCO CA 94104  
(415) 834-2300  
jlondon@gralegal.com  
For: The Clocal Government Commission Coalition

David Orth  
General Manager  
KINGS RVIER CONSERVATION DISTRICT  
4886 EAST JENSEN AVENUE  
FRESNO CA 93725  
(559) 237-5567  
dorth@krcd.org  
For: KINGS RIVER CONSERVATION DISTRICT

Edward J. Tiedemann  
Attorney At Law  
KRONICK, MOSKOVITZ, TIEDEMANN & GIRARD  
400 CAPITOL MALL, 27TH FLOOR  
SACRAMENTO CA 95814-4416  
(916) 321-4500  
etiedemann@kmtg.com  
For: Kings River Conservation District

G. Patrick Stoner  
LOCAL GOVERNMENT COMMISSION  
1414 K STREET, SUITE 600  
SACRAMENTO CA 95814  
(916) 448-1198 X 309  
pstoner@lgc.org

Paul Fenn  
LOCAL POWER  
4281 PIEDMONT AVE.  
OAKLAND CA 94611  
(510) 451-1727  
paulfenn@local.org  
For: Local Power

APPENDIX A

Page 3

Randall W. Keen  
Attorney At Law  
MANATT PHELPS & PHILLIPS, LLP  
11355 WEST OLYMPIC BLVD.  
LOS ANGELES CA 90064  
(310) 312-4361  
pucservice@manatt.com  
For: City of Corona

Roger Berliner  
MANATT, PHELPS & PHILLIPS  
11355 W. OLYMPIC BLVD.  
LOS ANGELES CA 90064  
(310) 312-4000  
rberliner@manatt.com  
For: County of Los Angeles

David L. Huard  
RANDALL KERN  
Attorney At Law  
MANATT, PHELPS & PHILLIPS, LLP  
11355 WEST OLYMPIC BOULEVARD  
LOS ANGELES CA 90064  
(310) 312-4247  
dhuard@manatt.com  
For: City of Chula Vista

C. Susie Berlin  
Attorney At Law  
MC CARTHY & BERLIN, LLP  
2005 HAMILTON AVENUE, SUITE 140  
SAN JOSE CA 95125  
(408) 558-0950  
sberlin@mccarthyllaw.com  
For: City of Moreno Valley

Peter W. Hanschen  
SETH HILTON  
MORRISON & FOERSTER, LLP  
101 YGNACIO VALLEY ROAD, SUITE 450  
WALNUT CREEK CA 94563  
(925) 295-3450  
phanschen@mofo.com  
For: Constellation Newenergy, Inc.

James Tobin  
MORRISON AND FOERSTER LLP  
425 MARKET STREET, 28TH FLOOR  
SAN FRANCISCO CA 94105  
(415) 268-7678  
jtobin@mofo.com  
For: Pac-West Telecomm, Inc.

Gene Ferris  
MOUNTAIN UTILITIES  
PO BOX. 205  
KIRKWOOD CA 95646  
(209) 258-7331  
gferris@ski-kirkwood.com

Sheryl Carter  
NATURAL RESOURCES DEFENSE COUNCIL  
111 SUTTER STREET, 20/F  
SAN FRANCISCO CA 94104  
(415) 875-6100  
scarter@nrdc.org  
For: NRDC

Cynthia Wooten  
NAVIGANT CONSULTING, INC.  
1126 DELAWARE STREET  
BERKELEY CA 94702  
(510) 559-8707  
cwootencohen@earthlink.net

John Dalessi  
NAVIGANT CONSULTING, INC.  
3100 ZINFANDEL DRIVE  
RANCHO CORDOVA CA 95852-1516  
(916) 631-3210  
jdalessi@navigantconsulting.com

Howard V. Golub  
NIXON PEABODY LLP  
TWO EMBARCADERO CENTER, STE. 2700  
SAN FRANCISCO CA 94111-3996  
(415) 984-8200  
hgolub@nixonpeabody.com  
For: California Clean Energy Resources Authority

Colin M. Long  
PACIFIC ECONOMICS GROUP  
201 SOUTH LAKE AVENUE, SUITE 400  
PASADENA CA 91101  
(626) 683-9395  
cmlong@earthlink.net  
For: Charles J. Cicchetti, PHD/The California Clean Energy Resources Authority

Claudia J. McClure  
PACIFIC GAS AND ELECTRIC COMPANY  
PG&E MAIL CODE B9A  
PO BOX 770000  
SAN FRANCISCO CA 94177  
(415) 973-6125  
cjm1@pge.com  
For: PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

Page 4

Craig M. Buchsbaum  
PETER OUBORG  
Attorney At Law  
PACIFIC GAS AND ELECTRIC COMPANY  
PO BOX 7442  
SAN FRANCISCO CA 94120  
(415) 973-4844  
cmb3@pge.com  
For: Pacific Gas and Electric Company

Lucy Fukui  
PACIFIC GAS AND ELECTRIC COMPANY  
MAIL CODE B9A  
77 BEALE ST.  
SAN FRANCISCO CA 94105  
(415) 973-7101  
lgk2@pge.com  
For: Pacific Gas and Electric Company

Peter Ouborg  
Attorney At Law  
PACIFIC GAS AND ELECTRIC COMPANY  
77 BEALE STREET, ROOM 3163  
SAN FRANCISCO CA 94105  
(415) 973-2286  
pxo2@pge.com  
For: Pacific Gas and Electric Company

Stacy Walter  
Attorney At Law  
PACIFIC GAS AND ELECTRIC COMPANY  
PO BOX 7442  
SAN FRANCISCO CA 94120-7442  
(415) 973-6611  
sww9@pge.com  
For: Pacific Gas and Electric Company

Robert W. Marshall  
General Manager  
PLUMAS-SIERRA RURAL ELECTRIC CO-OP  
PO BOX 2000  
PORTOLA CA 96122-2000

Matthew Gorman  
Deputy City Attorney  
POMONA CITY ATTORNEY'S OFFICE  
505 S. GAREY AVE.  
POMONA CA 91769  
(909) 620-2071  
matt.gorman@ci.pomona.ca.us

Daniel W. Meek  
Attorney At Law  
RESCUE  
10949 S.W. 4TH AVENUE  
PORTLAND OR 97219  
(503) 293-9021  
dan@meek.net

Steven Moss  
S. F. COMMUNITY POWER COOPERATIVE  
1307 EVANS STREET  
SAN FRANCISCO CA 94124  
(415) 550-7155  
steven@moss.net  
For: Golden State Cooperative/SF Co-op

Paul A. Szymanski  
Attorney At Law  
SAN DIEGO GAS & ELECTRIC COMPANY  
101 ASH STREET  
SAN DIEGO CA 92101  
(619) 699-5078  
pszymanski@sempra.com

Steve Rahon  
Sempra Energy Utilities  
SAN DIEGO GAS & ELECTRIC COMPANY  
8315 CENTURY PARK COURT  
SAN DIEGO CA 92123  
(858) 654-1773  
srahon@semprautilities.com

Fraser D. Smith  
City And County Of San Francisco  
SAN FRANCISCO PUBLIC UTILITIES COMM  
1155 MARKET STREET, 4TH FLOOR  
SAN FRANCISCO CA 94103  
(415) 554-1572  
fsmith@sfwater.org  
For: SFPUC

Sean Casey  
SAN FRANCISCO PUBLIC UTILITIES COMMISSIO  
1155 MARKET STREET, 4TH FLOOR  
SAN FRANCISCO CA 94103  
(415) 554-1551  
scasey@sfwater.org  
For: City/County of San Francisco

APPENDIX A

Page 5

Amy Peters  
Regulatory Case Administrator  
SEMPRA ENERGY UTILITIES  
8330 CENTURY PARK COURT -CP32D  
SAN DIEGO CA 92123-1530  
(858) 654-1796  
apeters@semprautilities.com  
For: San Diego Gas & Electric

Richard Esteves  
SESCO, INC.  
77 YACHT CLUB DRIVE, SUITE 1000  
LAKE HOPATCONG NJ 07849-1313  
(973) 663-5125  
sesco@optonline.net

David M. Norris  
Attorney At Law  
SIERRA PACIFIC POWER COMPANY  
PO BOX 10100  
6100 NEIL ROAD  
RENO NV 89520  
(775) 834-5696  
dnorris@sppc.com

Jennifer Shigekawa  
Attorney At Law  
SOUTHERN CALIFORNIA EDISON COMPANY  
2244 WALNUT GROVE AVENUE  
ROSEMEAD CA 91770  
(626) 302-6819  
Jennifer.Shigekawa@sce.com  
For: Southern California Edison Company

Ronald Moore  
SOUTHERN CALIFORNIA WATER CO.  
630 EAST FOOTHILL BOULEVARD  
SAN DIMAS CA 91773  
(909) 394-3600 X 682

Matthew Freedman  
HAYLEY GOODSON  
Attorney At Law  
THE UTILITY REFORM NETWORK  
711 VAN NESS AVENUE, SUITE 350  
SAN FRANCISCO CA 94102  
(415) 929-8876 X 314  
freedman@turn.org  
For: TURN

Paul Szymanski  
Attorney At Law  
SEMPRA ENERGY  
101 ASH STREET  
SAN DIEGO CA 92101  
(619) 699-5078  
pszymanski@sempra.com  
For: San Diego Gas & ElectricCompany

Mike Florio  
THE UTILITY REFORM NETWORK  
711 VAN NESS AVENUE, SUITE 350  
SAN FRANCISCO CA 94102  
(415) 929-8876  
mflorio@turn.org  
For: TURN

\*\*\*\*\* STATE EMPLOYEE \*\*\*\*\*

Kathryn Auriemma  
Energy Division  
RM. 4002  
505 VAN NESS AVE  
San Francisco CA 94102  
(415) 703-2072  
kdw@cpuc.ca.gov

Truman L. Burns  
Office of Ratepayer Advocates  
RM. 4102  
505 VAN NESS AVE  
San Francisco CA 94102  
(415) 703-2932  
txb@cpuc.ca.gov

Gloria Bell  
CALIFORNIA DEPARTMENT OF WATER RESOURCES  
3310 EL CAMINO AVENUE, SUITE 120  
SACRAMENTO CA 95821  
(916) 574-1299  
gbell@water.ca.gov  
For: CALAIFORNIA DEPARTMENT OF WATER RESOURCES

Jeannie S. Lee  
Office Of Chief Counsel  
CALIFORNIA DEPARTMENT OF WATER RESOURCES  
3310 EL CAMINO AVE, SUITE 120  
SACRAMENTO CA 95821  
(916) 574-2220  
jslee@water.ca.gov  
For: CALIFORNIA DEPARTMENT OF WATER RESOURCES

## APPENDIX A

## Page 6

Hassan Mohammed  
CALIFORNIA ENERGY COMMISSION  
1516 9TH STREET, MS43  
SACRAMENTO CA 95814  
(916) 651-9855  
hmohamme@energy.state.ca.us

Jennifer Tachera  
CALIFORNIA ENERGY COMMISSION  
1516 - 9TH STREET  
SACRAMENTO CA 95814  
(916) 654-3870  
jtachera@energy.state.ca.us

Amy Chan  
Energy Division  
AREA 4-A  
505 VAN NESS AVE  
San Francisco CA 94102  
(415) 355-5532  
amy@cpuc.ca.gov

Cheryl Cox  
Executive Division  
RM. 5218  
505 VAN NESS AVE  
San Francisco CA 94102  
(415) 703-2221  
cxc@cpuc.ca.gov

Christopher Danforth  
Office of Ratepayer Advocates  
RM. 4209  
505 VAN NESS AVE  
San Francisco CA 94102  
(415) 703-1481  
ctd@cpuc.ca.gov

Julie A Fitch  
Executive Division  
RM. 5203  
505 VAN NESS AVE  
San Francisco CA 94102  
(415) 355-5552  
jf2@cpuc.ca.gov

Maxine Harrison  
Executive Division  
RM. 500  
320 WEST 4TH STREET SUITE 500  
Los Angeles CA 90013  
(213) 576-7064  
omh@cpuc.ca.gov

John Pacheco  
California Energy Resources Scheduling  
CALIFORNIA DEPARTMENT OF WATER RESOURCES  
3310 EL CAMINO AVENUE, ROOM 120  
SACRAMENTO CA 95821  
(916) 574-0311  
jpacheco@water.ca.gov  
For: CALIFORNIA DEPARTMENT OF WATER RESOURCES

Diana L. Lee  
Legal Division  
RM. 4300  
505 VAN NESS AVE  
San Francisco CA 94102  
(415) 703-4342  
dil@cpuc.ca.gov

Jeanette Lo  
Energy Division  
RM. 4006  
505 VAN NESS AVE  
San Francisco CA 94102  
(415) 703-1825  
jlo@cpuc.ca.gov

Alan Lofaso  
Executive Division  
770 L STREET, SUITE 1050  
Sacramento CA 95814  
(916) 327-7788  
alo@cpuc.ca.gov

Kim Malcolm  
Administrative Law Judge Division  
RM. 5005  
505 VAN NESS AVE  
San Francisco CA 94102  
(415) 703-2822  
kim@cpuc.ca.gov

Lainie Motamedi  
Division of Strategic Planning  
RM. 5119  
505 VAN NESS AVE  
San Francisco CA 94102  
(415) 703-1764  
lrm@cpuc.ca.gov

Craig McDonald  
NAVIGANT CONSULTING  
3100 ZINFANDEL DR., SUITE 600  
RANCHO CORDOVA CA 95670  
(484) 437-2487  
cmedonald@navigantconsulting.com  
For: California Department of Water Resources

**APPENDIX A**

**Page 7**

Steven C Ross  
Office of Ratepayer Advocates  
RM. 4209  
505 VAN NESS AVE  
San Francisco CA 94102  
(415) 703-2140  
sro@cpuc.ca.gov

Steve Roscow  
Energy Division  
AREA 4-A  
505 VAN NESS AVE  
San Francisco CA 94102  
(415) 703-1189  
scr@cpuc.ca.gov

Andrew Ulmer  
Attorney At Law  
SIMPSON PARTNERS LLP  
900 FRONT STREET, SUITE 300  
SAN FRANCISCO CA 94111  
(415) 773-1790  
andrew@simpsonpartners.com  
For: California Department of Water Resources

Joel Tolbert  
Office of Ratepayer Advocates  
RM. 4102  
505 VAN NESS AVE  
San Francisco CA 94102  
(415) 703-1742  
jlt@cpuc.ca.gov

Laura J. Tudisco  
Legal Division  
RM. 5032  
505 VAN NESS AVE  
San Francisco CA 94102  
(415) 703-2164  
ljt@cpuc.ca.gov

**(END OF APPENDIX A)**

**APPENDIX B**  
**ASSEMBLY BILL 117**

**APPENDIX B****Page 1**

AB 117

Public Utilities Code

366.2. (a) (1) Customers shall be entitled to aggregate their electric loads as members of their local community with community choice aggregators.

(2) Customers may aggregate their loads through a public process with community choice aggregators, if each customer is given an opportunity to opt out of their community's aggregation program.

(3) If a customer opts out of a community choice aggregator's program, or has no community choice program available, that customer shall have the right to continue to be served by the existing electrical corporation or its successor in interest.

(b) 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.

(c) (1) Notwithstanding Section 366, a community choice aggregator is hereby authorized to aggregate the electrical load of interested electricity consumers within its boundaries to reduce transaction costs to consumers, provide consumer protections, and leverage the negotiation of contracts. However, the community choice aggregator may not aggregate electrical load if that load is served by a local publicly owned electric utility, as defined in subdivision (d) of Section 9604. A community choice aggregator may group retail electricity customers to solicit bids, broker, and contract for electricity and energy services for those customers. The community choice aggregator may enter into agreements for services to facilitate the sale and purchase of electricity and other related services. Those service agreements may be entered into by a single city or county, a city and county, or by a group of cities, cities and counties, or counties.

(2) Under community choice aggregation, customer participation may not require a positive written declaration, but all customers shall be informed of their right to opt out of the community choice aggregation program. If no negative declaration is made by a customer, that customer shall be served through the community choice aggregation program.

(3) A community choice aggregator establishing electrical load aggregation pursuant to this section shall develop an implementation plan detailing the process and consequences of aggregation. The implementation plan, and any subsequent changes to it, shall be considered and adopted at a duly noticed public hearing. The implementation plan shall contain all of 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.



**APPENDIX B****Page 2**

(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.

(5) 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).

(6) The commission shall notify any electrical corporation serving the customers proposed for aggregation that an implementation plan initiating community choice aggregation has been filed, within 10 days of the filing.

(7) Within 90 days after the community choice aggregator establishing load aggregation files its implementation plan, 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 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).

(8) No entity proposing community choice aggregation shall act to furnish electricity to electricity consumers within its boundaries until the commission determines the cost-recovery that must be paid by the customers of that proposed community choice aggregation program, as provided for in subdivisions (d), (e), and (f). The commission shall designate the earliest possible effective date for implementation of a community choice aggregation program, taking into consideration the impact on any annual procurement plan of the electrical corporation that has been approved by the commission.

(9) 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. Electrical corporations shall continue to provide all metering, billing, collection, and customer service to retail customers that participate in community choice aggregation programs. Bills sent by the electrical corporation to retail customers shall identify the community choice aggregator as providing the electrical energy component of the bill. The commission shall determine the terms and conditions under which the electrical corporation provides services to community choice aggregators and retail customers.

(10) (A) A city, county, or city and county that elects to implement a community choice aggregation program within its

**APPENDIX B****Page 3**

jurisdiction pursuant to this chapter shall do so by ordinance.

(B) Two or more cities, counties, or cities and counties may participate as a group in a community choice aggregation pursuant to this chapter, through a joint powers agency established pursuant to Chapter 5 (commencing with Section 6500) of Division 7 of Title 1 of the Government Code, if each entity adopts an ordinance pursuant to subparagraph (A).

(11) Following adoption of aggregation through the ordinance described in paragraph (10), the program shall allow any retail customer to opt out and to continue to be served as a bundled service customer by the existing electrical corporation, or its successor in interest. Delivery services shall be provided at the same rates, terms, and conditions, as approved by the commission, for community choice aggregation customers and customers that have entered into a direct transaction where applicable, as determined by the commission.

Once enrolled in the aggregated entity, 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 amounts previously determined and paid pursuant to subdivisions (d), (e), and (f) from the cost of reentry.

(12) Nothing in this section shall be construed as authorizing any city or any community choice retail load aggregator to restrict the ability of retail electricity customers to obtain or receive service from any authorized electric service provider in a manner consistent with law.

(13) (A) The 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. Notifications may occur concurrently with billing cycles. Following enrollment, the aggregated entity shall fully inform participating customers for not less than two consecutive billing cycles. Notification may include, but is not limited to, direct mailings to customers, or inserts in water, sewer, or other utility bills. Any notification shall inform customers of both of the following:

(i) That they are to be automatically enrolled and that the customer has the right to opt out of the community choice aggregator without penalty.

(ii) The terms and conditions of the services offered.

(B) The community choice aggregator may request the commission to approve and order the electrical corporation to provide the notification required in subparagraph (A). If the commission orders the electrical corporation to send one or more of the notifications required pursuant to subparagraph (A) in the electrical corporation's normally scheduled monthly billing process, the electrical corporation shall be entitled to recover from the community choice aggregator all reasonable incremental costs it incurs related to the notification or notifications. The electrical corporation shall fully cooperate with the community choice aggregator in determining the feasibility and costs associated with using the electrical

**APPENDIX B****Page 4**

corporation's normally scheduled monthly billing process to provide one or more of the notifications required pursuant to subparagraph (A).

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

(14) The community choice aggregator shall register with the commission, which may require additional information to ensure compliance with basic consumer protection rules and other procedural matters.

(15) Once the community choice aggregator's contract is signed, the community choice aggregator shall notify the applicable electrical corporation that community choice service will commence within 30 days.

(16) Once notified of a community choice aggregator 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.

(17) An 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. 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.

(18) At 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. The electrical corporation shall read the metering devices and provide the data collected to the community aggregator at the aggregator's expense. To the extent that the community aggregator requests a metering location that would require alteration or modification of a circuit, the electrical corporation shall only be required to alter or modify a circuit if such alteration or modification does not compromise the safety, reliability or operational flexibility of the electrical corporation's facilities. All costs incurred to modify circuits pursuant to this paragraph, shall be born by the community aggregator.

(d) (1) 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 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. It is further the intent of the Legislature to prevent any shifting of recoverable costs between customers.

**APPENDIX B****Page 5**

(2) The Legislature finds and declares that this subdivision is consistent with the requirements of Division 27 (commencing with Section 80000) of the Water Code and Section 360.5, and is therefore declaratory of existing law.

(e) A retail end-use customer that purchases electricity from a community choice aggregator pursuant to this section shall pay both of the following:

(1) A charge equivalent to the charges that would otherwise be imposed on the customer by the commission to recover bond related costs pursuant to any agreement between the commission and the Department of Water Resources pursuant to Section 80110 of the Water Code, which charge shall be payable until any obligations of the Department of Water Resources pursuant to Division 27 (commencing with Section 80000) of the Water Code are fully paid or otherwise discharged.

(2) Any 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.

(f) A retail end-use customer purchasing electricity from a community choice aggregator pursuant to this section shall reimburse the electrical corporation that previously served the customer for all of the following:

(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.

(g) (1) Any charges imposed pursuant to subdivision (e) shall be the property of the Department of Water Resources. Any charges imposed pursuant to subdivision (f) shall be the property of the electrical corporation. The commission shall establish mechanisms, including agreements with, or orders with respect to, electrical corporations necessary to ensure that charges payable pursuant to this section shall be promptly remitted to the party entitled to payment.

(2) Charges imposed pursuant to subdivisions (d), (e), and (f) shall be nonbypassable.

(h) Notwithstanding Section 80110 of the Water Code, the commission shall authorize community choice aggregation only if the commission imposes a cost-recovery mechanism pursuant to subdivisions (d), (e), (f), and (g). Except as provided by this subdivision, this section shall not alter the suspension by the commission of direct purchases of electricity from alternate providers other than by community choice aggregators, pursuant to Section 80110 of the Water Code.

(i) (1) The commission shall not authorize community choice

**APPENDIX B**

**Page 6**

aggregation until it implements a cost-recovery mechanism, consistent with subdivisions (d), (e), and (f), that is applicable to customers that elected to purchase electricity from an alternate provider between February 1, 2001, and January 1, 2003.

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

(3) The commission shall not authorize community choice aggregation until it has adopted rules for implementing community choice aggregation.

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

**(END OF APPENDIX B)**