Decision **03-04-030** April 3, 2003

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding the Implementation of the Suspension of Direct Access Pursuant to Assembly Bill 1X and Decision 01-09-060.	Rulemaking 02-01-011 (Filed January 9, 2002)

OPINION ON COST RESPONSIBILITY SURCHARGE MECHANISMS FOR CUSTOMER GENERATION DEPARTING LOAD

TABLE OF CONTENTS

OPINION ADOPTING COST RESPONSIBILITY SURCHARGE MECHANISMS FOR CUSTOMER GENERATION DEPARTING LOAD

I. Introduction

Except as discussed herein, today's decision adopts policies and mechanisms related to cost responsibility surcharges (CRS) applicable to "Departing Load" (DL) served by "Customer Generation" within the service territories of California's three major electric utilities: Southern California Edison Company (SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E). We also reject a multi-party Settlement Agreement offered by parties to this phase of the proceeding as inconsistent with State and Commission policy, though we utilize portions of the settlement agreement to further articulate our policy with regard to CRS for DL.

DL, as used in this order, refers to that portion of the utility customer's electric load for which the customer: (a) discontinues or reduces its purchase of bundled or direct access service from the utility; (b) purchases or consumes electricity supplied and delivered by "Customer Generation" to replace the utility or Direct Access (DA) purchases; and (c) remains physically located at the same location or elsewhere within the utility's service territory as of the date on which this Commission decision becomes effective.[1] Reduction in load qualifies as DL as referenced in this order only to the extent that such load is subsequently served with electricity from a source other than the utility.

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[1] This definition does not apply to changes in the distribution of load among accounts as a customer site with multiple accounts, load resulting from the reconfiguration of distribution facilities on the customer site, provided that the changes do not result in a discontinuance or reduction of service from the Utility at that location. The definition also does not apply to departing load that physically disconnects from the utility grid.

This definition of departing load does not include, nor would any CRS charges adopted in this decision apply to:

- Changes in usage occurring in the normal course of business resulting from changes in business cycles, termination of operations, departure from the utility service territory, weather, reduced production, modifications to production equipment or operations, changes in production or manufacturing processes, fuel switching, enhancement or increased efficiency of equipment or performance of existing Customer Generation equipment, replacement of existing Customer Generation equipment with new power generation equipment of similar size, installation of demand-side management equipment or facilities, energy conservation efforts, or other similar factors.
- New customer load or incremental load of an existing customer where the load is being met through a direct transaction with Customer Generation and the transaction does not otherwise requirement the use of transmission or distribution facilities owned by the utility.
- Load temporarily taking service from a back-up generation unit during emergency conditions called by the utility, the California Independent System Operator, or any successor system operator.

This definition generally conforms to utility tariffs. This order does not address any other forms of DL such as that served by municipally-owned utilities or irrigation districts.[2]

"Customer Generation" as used in this order, refers to cogeneration, renewable technologies, or any other type of generation that (a) is dedicated

[2] Nothing in this order should be construed as prejudging or limiting what Commission positions or treatment may be adopted for any other form of DL not covered in this order.

wholly or in part to serve a specific customer's load; and (b) relies on non-utility or dedicated utility distribution wires rather than the utility grid, to serve the customer, the customer's affiliates and / or tenant's, and / or not more than two other persons or corporations. Those two persons or corporations must be located on site or adjacent to the real property on which the generator is located. Parties also use the terms "distributed generation," "onsite and over-the-fence generation," and "self-generation" as being interchangeable with "Customer Generation."

The surcharge categories addressed in today's order cover the following:

1. Costs associated with procurement of power by the California Department of Water Resources (DWR), with separate charges for:

   (a) Historic shortfalls financed through a Bond Charge; and

   (b) Forward costs associated with the ongoing power charges

2. Costs associated with the Historic Procurement Charge ("HPC") (applicable to the SCE service territory only) pursuant to Decision (D.) 02-07-032, as modified by D.03-02-035.[3]

3. "Tail" Competition Transition Charge pursuant to Public Utilities Code Section 367(a).

As a context for resolving the issues addressed herein, we review the background leading to this order. This proceeding was opened to address issues relating to the suspension of DA.

[3] PG&E and SDG&E have not proposed, nor has the Commission addressed, any definition of HPC for their service territories. Thus, imposition of any HPC in PG&E or SDG&E service territories is outside the scope of this proceeding.

We suspended the right to acquire DA pursuant to legislative directive, as set forth in Assembly Bill (AB) No. 1 from the First Extraordinary Session (AB 1X). (Stats. 2001, Ch. 4.) This emergency legislation was enacted to respond to the serious situation in California when PG&E and SCE became financially unable to continue purchasing power due to extraordinary increases in wholesale energy prices.

The Governor's Proclamation of January 17, 2001,[4] and AB 1X required that DWR procure electricity on behalf of the customers in the service territories of the California utilities.[5] As part of its provisions to deal with California's energy crisis, AB 1X also called for the suspension of the right to acquire DA, as set forth in Section 80110 to the Water Code.

In compliance with this mandate, the Commission issued D.01-09-060, suspending the right to acquire DA after September 20, 2001. In that decision, we stated "that we may modify this order to include the suspension of all direct access contracts executed or agreements entered into on or after July 1, 2001." (D.01-09-060, mimeo., pp. 8-9.)

On January 14, 2002, the instant Rulemaking (R.) 02-01-011 was initiated to consider, among other things, whether a suspension date earlier than September 21, 2001 should apply to DA.[6] On March 27, 2002, we issued

[4] On January 17, 2001, Governor Davis issued a Proclamation that a "state of emergency" existed within California resulting from dramatic wholesale electricity price increases.

[5] This authority ended on December 31, 2002.

[6] The administrative record relating to these specific issues in Application (A.) 98-07-003 et al. was incorporated into this rulemaking. Judicial notice was also taken of specific information in the DWR Revenue Allocation Proceeding A.00-11-038 et al. (See Letter of January 25, 2002, to the parties that accompanied the Draft Decision of ALJ Barnett.)

D.02-03-055, determining that the DA suspension date should remain in effect as "after September 20, 2001." In D.02-03-055, we also determined that bundled service customers should not be burdened with additional costs due to cost shifting from the significant migration of customers from bundled to DA load between July 1, 2001 and September 21, 2002. We subsequently clarified that prevention of cost shifting meant that "bundled service customers are indifferent.[7]"

Proceedings were initiated to implement the necessary charges on DA load to prevent such cost shifting.[8] At the prehearing conference (PHC) held on February 22, 2002, certain parties advocated that cost responsibility should also include consideration of "Departing Load" customers. An administrative law judge (ALJ) ruling issued on March 29, 2002, prescribed that the scope of issues in this proceeding be expanded to include cost responsibility relating not only to DA, but also to DL.

In pleadings and testimony of parties in this proceeding, several terms have been used to refer to the charges to be imposed pursuant to D.02-03-055. These terms have included expressions such as nonbypassable charge, forward or ongoing costs, and exit fee. For the sake of uniformity and clarity, and consistent with D.02-11-022, we shall use the term "cost responsibility surcharge" (CRS) as an umbrella term taking into account all of the various charge

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[7] D.02-04-067, pp. 4-5.

[8] Proceedings to determine DA CRS were initiated by an ALJ ruling issued December 17, 2001 in A.98-07-003. By joint ruling on December 24, 2001, the issue of DA cost responsibility was transferred from A.98-07-003 to A.00-11-038 et al. Finally, D.02-04-052, issued on April 22, 2002, transferred consideration of cost responsibility issues from A.00-11-038 et al. to R.02-01-011.

components at issue in this proceeding that are applied to Customer Generation load.

Although the criteria and basis for determining the applicability of a CRS to Customer Generation is based on the record in this phase of the proceeding, the determination of specific cost elements relies upon certain methodologies set forth in D.02-11-022 applicable to DA customers, in conjunction with companion proceedings in A.00-11-038 et al.

II. Procedural Summary

Parties filed prehearing opening briefs on April 22, 2002, and reply briefs on May 6, 2002, on legal issues relating to the Commission's authority to impose cost responsibility charges both on DA and DL customers. Opening and reply testimony was submitted in June 2002 and addressed both DA and DL issues.

By ALJ oral ruling, DL issues were bifurcated into a separate hearing phase. Parties accordingly submitted supplemental testimony on September 11, 2002 and supplemental reply testimony on September 23, 2002. Evidentiary hearings on DL issues began on October 7, 2002 and continued intermittently through October 18, 2002.

During the course of the hearings, various parties ("Settling Parties") entered into settlement discussions on certain issues relevant to this phase. Pursuant to Rule 51.1 (b), on October 2, 2002, the Settling Parties issued a notice of settlement conference for October 9, 2002. A draft version of a Settlement Agreement was served on all parties on October 8, 2002. Subsequent to the settlement conference, all parties were given the opportunity to submit informal comments on the proposed settlement to the Settling Parties.

On October 17, 2002, a motion was filed for adoption of a Settlement Agreement sponsored jointly by a number of parties to the proceeding.[9] Because the scope of the Settlement Agreement addressed only Customer Generation, but not municipal load issues, the proceeding was further bifurcated.

Comments on the Settlement Agreement were filed on October 31, 2002, and reply comments on November 6, 2002.[10] In comments, various parties

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[9] The Joint Settling Parties include Arden Realty, Inc., Building Owners and Managers Association of California, California Energy Commission (CEC), California Independent Petroleum Association, Clarus Energy Partners, L.P., Cummins West, Inc., Energy Producers and Users Coalition (EPUC) [EPUC is an *ad hoc* coalition representing the electric end use and customer generation interests of the following companies: Aera Energy LLC, BP America Inc. (including Atlantic Richfield Company), Chevron U.S.A. Inc., Texaco Exploration and Production Inc., Equilon Enterprises LLC dba Shell Oil Products US, ExxonMobil Power and Gas Services Inc., on behalf of Exxon Mobil Corporation, THUMS Long Beach Company, Occidental Elk Hills, Inc., Tosco Corporation a Subsidiary of Phillips Petroleum Company, and Valero Refining Company – California], Goodrich Aerostructures Group, Hawthorne Power Systems, Hess Microgen, International Power Technology, Kern Oil and Refining Company, Kimberly Clark Corporation, next edge, Inc., Nextek Power Systems, Inc., PG&E, Onsite Energy Corporation, Paramount Petroleum Corporation, RealEnergy, Inc., Silicon Valley Manufacturing Group, Edison, The Utility Reform Network (TURN), University of California / California State University, and USS-POSCO Industries.

[10] The following parties submitted comments on the Settlement Agreement: Agricultural Energy Consumers Association (AECA), Alliance for Retail Energy Markets and the Western Power Trading Forum (AReM / WPTF), California Consumer Power and Conservation Financing Authority (CPA), California Large Energy Consumers Association (CLECA), California Solar Energy Industries Association (CalSEIA), Capstone Turbine Corporation, Ingersoll-Rand Energy Systems, Bowman Power Systems, CoGen Equipment Solutions, Inc., and Sempra Energy Connections (collectively, Capstone), Catholic Healthcare West (CHW), Center for Energy Efficiency and Renewable Technologies (CEERT), County of Los Angeles (LA County), County Sanitation Districts of Los Angeles (Districts), Eastside Power Authority (Eastside), Joint Settling Parties (as specified above), Office of Ratepayer Advocates (ORA) and SDG&E.

In addition, the South Coast Air Quality Management District (SCAQMD) submitted a letter to Commissioner Lynch dated October 30, 2002, and DWR filed reply comments on November 4, 2002, on the Settlement Agreement.

opposed certain provisions in the Settlement, and suggested alternative revisions. Only two parties, ORA and SDG&E, argued that the Settlement did not impose enough costs on Customer Generation load. The remaining parties opposed to the Settlement argued that it imposed too many costs on Customer Generation load.

Post-hearing opening briefs were filed on November 7, 2002 and reply briefs on November 14, 2002. In view of the settlement, parties shortened or waived certain cross-examination. The underlying testimony of witnesses in this phase of the proceeding was received into evidence without objection. In the joint motion, Settling Parties argue that no hearings are necessary prior to adoption of the Settlement Agreement in view of the evidentiary record already before the Commission. No party asked for evidentiary hearings on the merits of the Settlement Agreement. Accordingly, we conclude that written comments in response to the motion provide a sufficient basis to evaluate the merits of the Settlement Agreement in view of the evidentiary record on parties' underlying testimony that is already in the record.

Thus, the basis for adjudicating issues in this phase of the proceeding, the record consists of (1) the evidence developed through written testimony and oral cross examination on the underlying merits of issues in dispute and (2) the Settlement Agreement which represents a negotiated compromise of certain parties and the written comments filed in response to this agreement.

III. Overview of Parties' Positions

A. Pre-Settlement Positions

In their pre-settlement cases-in-chief, parties generally gravitated into one of two groups. There were also certain variations of parties' positions within a group.

One group, generally representing the views of bundled customers and utility interests was composed of the utilities, ORA, and TURN. Within this group, PG&E, SCE, ORA, and TURN all argued that DL that departed the utility system after January 17, 2001, should bear a share of both past and future costs on an essentially similar basis to their respective proposals for DA customers. SCE sought to recover an HPC element from customers that became DL after March 29, 2002, the date of the ALJ ruling formally notifying DL customers that such charges were being considered in this proceeding.

PG&E proposed that if exemptions were granted to a limited class of DL customers that install "super clean" and / or efficient DG units, such exemptions should be based upon an evaluation and policy conclusion that the benefits of encouraging these DG technologies outweighs the cost-shifting burden other customers will have to bear.

SDG&E proposed that DWR Bond Charges be recovered from all customers, including all forms of DL that remain directly or indirectly connected to the grid. SDG&E also proposed that DL served by customer self-generation generally be excluded from paying for DWR ongoing power charges, based on the premise that DWR did not incur costs to serve this load. SDG&E is already recovering a competition transition cost (CTC) component from DL customers under its existing tariffs, and proposes no change in that process. SDG&E argues that a surcharge should apply only to DL that was not anticipated by DWR when it made purchases and for which it incurred costs that became stranded.

The other major group of parties generally comprised interests representing various aspects of the Customer Generation market. In their pre-settlement testimony, these parties generally opposed imposition of any surcharges on DL customers, citing legal, factual, and policy reasons. Parties cite state and federal statutes, including AB 1890, AB 1X, Public Utilities Code

Sections 216 and 281, and the Public Utilities Regulatory Policies Act (PURPA) to support their claims. Parties argue that Customer Generation projects are more appropriately characterized as demand reduction or energy efficiency measures that provide quantifiable benefits to customers and the state's energy grid.

Certain parties, including EPUC / KCC / GAG, UC / CSU, AREM, and CalSEIA, argued that the Commission lacked legal authority and a policy basis upon which to impose these charges retroactively. EPUC et al. argue that Public Utilities Code Section 218(a) and (b) place customer-owned generation outside the scope of this Commission's jurisdiction, and that it is subject only to Federal Energy Regulatory Commission (FERC) regulation pursuant to PURPA. These parties argue that the Commission does not have the authority to impose a surcharge for DWR costs or costs for purchased power from qualifying facilities (QFs) and utilities' retained generation. To the extent that the Commission retains any right to regulate customer generation, they claim that it is limited to the development of standby service charges.

These parties contrast the Legislature's decision to authorize the suspension of new direct access contracts (Water Code § 80110), with the Legislature's strong support for the construction of new generation, particularly cogeneration and distributed generation. These parties cite legislation such as Assembly Bill No. 970 (AB 970), Stats. 2000, ch. 329, and Senate Bill 28 of the First Extraordinary 2001-2002 Session ("SB 28"), (Stats. 2001, ch. 12), as intending to encourage private investment in new generating facilities in order to relieve the strain upon the state's system. Given the recent cancellations and delays in the planned construction of large power plants in the state, they argue that the need for small generation facilities is even more critical. Parties further argue that Customer Generation did not cause DWR to incur costs, and accordingly, such generation should not be subject to surcharges.

B. The Settlement Agreement

The Settlement Agreement proposes that DL that began to receive service from onsite or over-the-fence generation after January 17, 2001 shall pay a "DWR Shortfall Charge" equal to 72% of the DWR bond charge imposed on bundled service customers.[11] "Existing" and "grandfathered" DL are exempt from paying any surcharge for DWR's ongoing costs, as is DL served by new onsite or over-the-fence generation up to an annual megawatt ("MW") cap.[12] DL covered by the Settlement Agreement is required to continue to contribute toward the recovery of costs in SCE's Procurement Related Obligation Account (PROACT).[13] Finally, the Settlement Agreement provides that DL that is not statutorily exempt from paying CTC shall pay a tail CTC consisting of the components specified in Public Utilities Code Section 367(a).[14]

The Settlement Agreement does not address certain issues that Settling Parties do not consider to be fully ripe for determination, such as the applicability of an HPC for PG&E, or how, if at all, generator refunds in pending FERC dockets would apply to DL customers. The Settlement Agreement likewise does not address narrow issues that Settling Parties believe are better left to case-specific applications. For example, specific questions relating to the implementation of charges at customer sites with multiple accounts, and sites at which the customer maintains no utility connection are not addressed in the Settlement. The Settlement Agreement also does not address the question of exemption from CRS for "eligible customer generators" as defined in Public

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[11] Settlement Agreement, § 5.

[12] Settlement § 6.

[13] Settlement § 7.

[14] Settlement § 8.

Utilities Code Section 2827(b)(2), or eligible biogas digester customer-generator" as defined in Public Utilities Code Section 2827.9.

ORA and SDG&E oppose the "Shortfall" charge, and argue instead that a full share of the DWR Bond Charge should apply on the same pro rata basis as for bundled and DA customers. ORA also opposes the exclusions from ongoing DWR power charges pursuant to the proposed megawatts (MW) cap. Other parties representing CG interests opposed the Settlement for opposite reasons, arguing against imposition of any surcharges on the basis that it would be contrary to public policy and statutory mandates in favor of developing new sources of alternative generation. We address the substance of parties' objections in the discussion of each specific element of CRS, as set forth below.

IV. Contested Issues and Positions of Parties

A. Recovery of DWR Bond Charges

1. Background

Current bundled customers, such as DL customers who received bundled service subsequent to January 17, 2001, did not pay fully for the DWR's procurement costs incurred during 2001. In order to reduce the immediate rate impact, DWR anticipated financing a part of the costs incurred during 2001 at the highest recovery levels by issuing bonds. Under AB 1X, the revenue shortfall for the historic period was to be financed through the sale of State of California Bonds. In D.02-02-051, the Commission adopted a "Rate Agreement" governing the terms by which the Bonds would be administered. As stated in D.02-02-051:

> Under the Act, the Commission has an obligation to impose charges on electric customers that are sufficient to compensate DWR for its costs under the Act, including procuring and delivering power, and paying bond principal and interest.

> The adopted Rate Agreement establishes two streams of revenues. One stream of revenues will come from Bond Charges imposed on electric customers, and is designed to pay for bond-related costs. The second stream of revenues will come from Power Charges imposed on electric customers who buy power from DWR, and is designed to pay for the costs that DWR incurs to procure and deliver power. Both streams of revenue are necessary for DWR to issue bonds with investment-grade ratings.

In D.02-11-022, we directed that a Bond Charge be imposed on DA customers (other than those that have remained continuously on DA service) on a cents / kilowatts-hour (kWh) basis equivalent to that imposed on bundled customers. The actual determination of the revenue requirement and per-customer bond charge, however, was to be implemented in A.00-11-038 et al. (the "Bond Charge" phase).[15] On October 24, 2002, D. 02-10-063 was issued, adopting a methodology for developing a DWR Bond Charge.

D.02-10-063 was amended on rehearing by D.02-11-074. As explained in that order, DWR was to file by November 8, 2002, its more precise 2003 bond revenue requirement for bond-related costs with the Energy Division once the bonds have been placed and DWR has determined its actual bond-related charges. The utilities were then required to make compliance advice letter filings within five days following DWR's updated submission to impose a per kWh hour Bond charge on non-exempt bundled consumption delivered on and after November 15, 2002. SDGE, SCE, and PG&E were to calculate a uniform

[15] The Rate Agreement provides that the Commission may impose Bond Charges on DA customers only after (1) the Commission issues an order that provides for such charges, and (2) the order becomes final and unappealable. See Rate Agreement, Section 4.3, as attached to D.02-02-051.

per kWh charge by dividing the more precise 2003 bond revenue requirement by 106,222 GWh.[16]

The determination of whether, or to what extent, Customer Generation load should pay for bond-related costs was deferred to this phase. Pending the implementation of any actual bond charge recovery, we made provision in D.02-10-063 for the tracking of both DA and DL cost responsibility, and ordered each of the utilities to create a Bond-Charge Balancing Account (BCBA) for that purpose.

Once this instant decision becomes final and unappealable, the actual Bond Charge component of the CRS will be implemented for Customer Generation load, on the terms as set forth in this order, as discussed below.

2. Parties' Positions Prior to the Settlement

Prior to the settlement, two opposing views generally emerged concerning applicability of the Bond Charge. Parties representing utility and bundled customer interests (i.e., ORA and TURN) contended that DL should pay all charges related to the DWR bonds on the same basis as bundled customers.[17] Other parties proposed alternatives to a one-size-fits-all bond charge.[18]

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[16] The load figure represents total forecasted load minus excluded residential, DA, and DL.

[17] *See* PG&E Bond Charge Allocation Phase in Rate Stabilization Plan Opening Testimony, Ex. 90, at 4-1 to 4-4; *see also* SCE Proposal for DL Non-Bypassable Charges (Exit Fees), Ex. 76 at 4-7; *see also* Rebuttal Testimony of SCE on Proposals for DL Non-Bypassable Charges (Exit Fees), Ex. 77 at 1-15.

[18] *See* Proposed Supplemental Testimony of Scott Tomashefsky on Behalf of the California Energy Commission, Ex. 123 at 3-7; *see also* A.00-11-038 Prepared Direct Testimony of James A. Ross on Behalf of the Energy Producers and Users Coalition and Others, Ex. 600, at 5, Schedule 3; *see also* A.00-11-038 Ex. 3.

Parties representing Customer Generation interests advocated an opposing view. A number of parties claimed the Commission lacks authority to impose any charge related to the DWR bonds on DL.[19] Parties also argued that imposing Bond Charges would run counter to various state and federal mandates to encourage the development of preferred forms of alternative generation, and that there should be exemptions from DWR's past costs for small clean distributed generation,[20] for distributed solar generation,[21] and for certain other types of customer generation.[22]

3. Proposed Settlement Treatment

In Sections 5.3.1 and 5.3.2, the Settlement Agreement proposes to assess a DWR "Shortfall Charge" in lieu of a Bond Charge. The "Shortfall Charge" would apply only to customers that departed the utility to receive service from Customer Generation after January 17, 2001. The "Shortfall Charge" equals 72% of the Bond Charge that will be assessed on bundled customers in A.00-11-038 *et al.* This percentage level is premised on holding Customer Generation responsible only for the DWR historical shortfall incurred during

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[19] See Initial Brief of the Energy Producers and Users Coalition, Kimberly Clark Corporation and Goodrich Aerostructures Group on the Commission's Legal Authority to Impose DL Surcharges and Exit Fees at (EPUC / KCC / GAG Initial Brief) at 16-19, 25-29; see also Reply Testimony of Maric Munn and Mark Gutheinz on Behalf of the University of California and California State University Relating to Cost Responsibility for Direct Access and Departing Load Customers, Ex. 126, at 9-13; see also Reply Testimony of Steven A. Greenberg on Behalf of RealEnergy, Inc. and Joint Parties Interested in Distributed Generation / Distributed Energy Resources, Ex. 82 at 4-7.

[20] Capstone Comments, pp. 6–7.

[21] CalSEIA Comments, pp. 11–24.

[22] Districts Comments, p. 10.

2001 and a proportionate share of costs related in general to issuance bonds to amortize this shortfall.

The 72% factor is based on a ratio of (1) a hypothetical bond issuance of $8.6 billion and (2) the approximate actual bond issuance, estimated at about $11.95 billion, as derived by a DWR in a data response contained in Exhibit 3 of the Bond Charge proceedings in A.00-11-038 et al. The derivation of the $8.6 billion hypothetical shortfall is set forth in Appendix C to the Settlement Agreement. As explained in DWR's Response to Data Request No. 3:

> "A hypothetical … bond issue [of $8.6 billion]… would generate sufficient bond proceeds to: finance the Department's undercollections through September 20, 2001; finance the carrying costs of the undercollections from the date of cost incurrence through a hypothetical bond closing date of October 10, 2002; fund bond-related accounts at levels required to comply with the Bond Indenture; fund credit enhancement and issuance costs associated with the bonds. The sizing of the bond issue does not reflect any financing of any of the Department's power purchasing program reserves."[23]

DL customers, by paying the DWR Shortfall Charge provided in the Settlement Agreement, would contribute only to DWR's recovery of its Historical Shortfall and related administrative, financing and carrying costs, but not to the funding of reserve accounts that could be used for DWR forward costs and later reductions to bundled customer Bond Charges.[24]

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[23] A.00-11-038 et al., Ex. 3. Some DL parties had in fact advocated using an even smaller theoretical bond issuance to formulate a charge to recover DWR past costs from DL. *See* Reply Brief of the Energy Producers and Users Coalition, Kimberly Clark Corporation and Goodrich Aerostructures Group in A.00-11-038 et al. at 5.

[24] *See* Opening Brief of the Energy Producers and Users Coalition, Kimberly Clark Corporation and Goodrich Aerostructures Group in A.00-11-038, Bond Charge Phase, at 6-15.

Section 5.3.2.1 calls for Customer Generation load to pay a full 20-year bond charge at the 72% ratio although bundled customers are expected to pay a reduced bond charge for the last few years of the amortization due to the use of operating reserves to reduce power charges or to pay down the bonds. Bundled and DA customers pre-fund deposit and reserve accounts associated with the DWR bond issue and receive the benefits of these funds over the life of the bonds. Customer Generation DL would neither pre-fund the deposit and reserve accounts associated with the bond issue nor receive the benefits of these funds during the life of the bonds.

4. Parties' Positions in Opposition to the Settlement

SDG&E and ORA oppose the Shortfall Charge, arguing that Departing Load should bear the same DWR Bond Charge as bundled customers. SDG&E and ORA argue that the Settlement's proposed approach contradicts the treatment applied to DA customers, as adopted in D.02-11-022 which reflected 100% of the Bond Charge revenue requirement. In view of the Commission's rejection of a partial bond charge for DA customers, ORA and SDG&E argue that the Agreement should be amended to make it consistent with the treatment of the DA. If the Agreement were altered to apply a uniform Bond Charge equivalent that applied to direct access customers, then the whole calculation and qualification sections of Section 5.3 would become superfluous (with the exception of 5.3.3 which allows a lump sum payment of the bond charge).

Settling Parties defend the 72% Shortfall Charge, arguing that it merely represents an alternative rate design. Although the Commission rejected "double-counting" arguments in D.02-11-022, Settling Parties argue that they have used a different rationale to justify their proposal. DL parties do not claim that a full Bond Charge constitutes double-counting, but instead, maintain that the DWR Bond Charge "impermissibly co-mingled" past and forward costs. DL parties contend that to the extent that forward costs are not recoverable from DL customers, such customers that depart the grid will not receive any offsetting benefit from the funding of forward costs. Therefore, if the Commission decides to apply a charge for DWR Historical Shortfall to DL, Settling Parties claim that charge should recover only costs related to the Historical Shortfall.[25] The Settling Parties argue that the DWR Shortfall Charge will not result in any net harm to other customers, given that DL will not receive future benefits of accounts they do not fund, and bundled service customers are assured that DL will contribute to recovery of DWR Historical Costs.[26]

ORA and SDG&E contend that DL customers still receive a disproportionate benefit in the early years through a reduced bond charge in exchange for bundled customers bearing the risk surrounding the future risk of funds in the operating reserves. ORA and SDG&E argue that this is not fair.

On the other hand, various parties representing Customer Generation interests take the opposite position, arguing that even the Shortfall Charge is too much, and that in fact, no shortfall charge should be assessed at all, particularly for certain preferred categories of alternative generation. These arguments essentially apply both to the historic as well as the ongoing DWR charges.

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[25] *See* Opening Brief of EPUC / KCC / GAG in A.00-11-038 et al. at 3-10.

[26] Settling Parties contend that either including or excluding DL in the Bond Charge calculation would have a negligible effect on the bond charge for bundled service customers. *See* D.02-10-063, p. 29 ("policies to either [completely] exclude or include DL in paying for bond-related costs will impact bond-related charges of less than .005 cents per kWh").

B. DWR Ongoing Power Costs

1. Positions of Parties Prior to the Settlement

In their cases-in-chief, PG&E and SCE proposed that Customer Generation loads that departed from utility service after January 17, 2001, when DWR entered the procurement market on behalf of utility customers, should not be allowed to escape their fair share of DWR's ongoing power costs. PG&E argues that all customers on PG&E's system, as of January 17, 2001, benefited from DWR's role as "default provider." PG&E and SCE do not propose to apply any DWR charges to customers that departed its system prior to January 17, 2001, since such customers never benefited from DWR-procured power.

SDG&E does not propose to charge any Customer Generation load for DWR-related ongoing power charges. SDG&E does not believe that assessing such charges is warranted, arguing that DWR did not incur costs on behalf of such customers, but assumed they would procure their power independently of DWR through self-generation.

TURN proposed that Customer Generation should pay for ongoing DWR power charges, with the exception of those eligible for standby charge exemptions (net metered customers plus new Customer Generation under five MW installed before the specific dates established by legislation). TURN believes that this limited exemption would avoid double-counting of charges that are already collected in those standby charges.

ORA proposes that all Customer Generation load should bear a share of the ongoing DWR power charge. ORA recommends, for now, adoption of an identical surcharge applicable both to direct access and departing load based on Navigant's modeling of the cost-impact of last year's return of a substantial load from bundled service to direct access. Any surcharge true-up in 2003 or 2004 could then capture incremental cost impacts of departing load.

ORA anticipates the three utilities will actually implement a surcharge related to departing load via existing rate schedules.[27]

2. Position of Parties to the Settlement Agreement

The Settlement Agreement provides that DL shall pay a component for DWR ongoing power charges, subject to certain specified exclusions, equal to per-kWh cost responsibility component adopted for DA customers in this proceeding to recover DWR purchases. The DWR ongoing power charge component would apply on or after January 1, 2003, provided that the charge would not apply to

- Existing load served by Customer generation that departed utility service on or before January 17, 2001;
- "Grandfathered" DL that becomes operational on or before January 1, 2003, or that submitted its CEQA application on or before August 29, 2001 and becomes operational on or before January 1, 2004;
- "Qualifying" New DL that falls within an annual megawatt cap.[28]

The MW cap proposed in the Settlement Agreement is based on the forecast of Customer Generation that was available to DWR at the time the contracts were being negotiated. Settling Parties argue that there is therefore a logical connection between the amount of Customer Generation excluded from

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[27] For example, PG&E Schedule E-Depart.

[28] For ease of exposition, parties' comments generally refer to "a cap" as if it was a single annual figure. In fact, the caps vary by year corresponding with DWR's forecasts (see Settlement Agreement, Appendix A).

going-forward costs and the amount of Customer Generation for which DWR was not negotiating contracts.

3. Comments on the Settlement

Various parties filed comments in support of the Settlement Agreement's treatment of forward-looking DWR power costs. CPA endorses the Settlement Agreement's exemption for new, qualifying distributed generation, up to the proposed annual caps as being consistent with DWR's planning assumptions in contracting for long-term power resources, and also meeting the Authority Board of Director's policy goal to seek exemption from surcharges for a minimum of 200 MW of clean Distributed Generation per year.[29] CMTA likewise agrees with this approach and believes that such a cap reflects the fact that DWR assembled its portfolio of generation supplies under the assumption that customers would continue to avail themselves of self-generation.[30]

Certain parties also opposed the Settlement's proposed treatment of DWR ongoing costs. Controversy focused primarily around the provisions relating to the proposed MW cap. ORA argues that the cap is too high, to the point that "it equals a complete exemption in fact."[31] Others argue that the cap does not go far enough, but that additional load should be excluded from DWR power charges.

a) Position of ORA

ORA argues that the size of the cap exemption is in conflict with the public interest that Departing Load customers contribute to ongoing power purchase costs to prevent any shift of costs to bundled customers. ORA notes

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[29] CPA Comments, p. 1.

[30] CMTA Comments, p. 3.

[31] ORA Comments, p. 11.

that the amount of this load could cumulatively total 2,958 MW of load.[32] For perspective, ORA states that this total is almost equivalent to SDG&E's current peak load forecast (3,255 MW) and represents 25% of the current capacity under long term power contracts by DWR. ORA believes that the cap emaciates Section 6.1 of the Settlement which states, "Departing Load shall pay its share of CDWR Forward Costs as provided in this Section." (Settlement Agreement, p. 8.) The Summary of the Agreement at Section 2.2.3 states in part:

> "The megawatt cap reflects the amount of reduction for Customer Generation in the forecast relied upon by the CDWR in negotiating forward purchase obligations." (Settlement Agreement, p. 2.)

ORA argues, however, that there is no proof to support Section 2.2.3, directly linking the forecast of electric load made by Navigant to the actual contracting and purchasing decisions of DWR on behalf of utility customers, but only vague assertions and general statements made by some parties. ORA believes that any attempt to adjust the DA surcharge to account for a forecast of departing load would be highly speculative, resulting in new levels of complexity, and involving more computer runs by DWR.

ORA argues that although Navigant "assumed" the IOU forecasts included Customer Generation,[33] DWR Witness McDonald "never saw any explicit assumptions [from PG&E or SDG&E].[34]" Witness Keane testified

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[32] The actual amount of DL which the settlement proposes avoid an on-going CDWR cost responsibility charge is unknown. This occurs due to the exemption for projects cited in 6.2.2.1 combined with an unknown figure for existing (that is pre January 17, 2001) self or customer generation.

[33] DWR / McDonald Reporter's Transcripts ("RT"), p. 1471:3-4,

[34] DWR / McDonald, RT, p. 1471:5-16

that PG&E didn't provide any forecasts to DWR until June of 2001.[35] ([T]his [forecast] was given to DWR after most of its contracts had already been entered into.[36]

ORA argues that, even assuming that the Navigant forecasts estimated DG forecasts, there is no evidence that DWR used the Navigant forecasts to determine procurement needs. Navigant witness McDonald stated, "Our job was generally to give [the contracting teams] the facts and not to make recommendations in terms of how much they should be buying or the specifics of the contracts.[37]" ORA contends that while DWR may have known Navigant's "net result" but "they did not know even how much of it was conservation versus distributed generation." (*Id.* at 1475:15-17 and 1483:21-24.)

ORA believes that while the net short forecasts provided by Navigant served perhaps as a "guide," they did not determine how much power DWR ultimately would be forced to contractually purchase. ORA argues that exemption of a substantial amount of utility load from any on-going cost responsibility of the DWR contracts should not be based on such a tenuous link between the forecast of net short requirements and the actual contract outcomes, particularly given DWR's weak bargaining position in what was a sellers' market.

ORA offers its own alternative proposed MW caps on DL exemptions from DWR ongoing power charges, as set forth in Appendix A of ORA's comments on the Settlement Agreement. ORA's alternative caps

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35 PG&E / Keane RT, p. 1788:3-15.

36 PG&E / Keane RT, p. 1800:24-28.

37 DWR / McDonald RT, p. 1472:16-19.

represent a significant reduction in DL exemptions compared with the Settlement Agreement.

b) Position of Parties Representing Customer Generation Interests

Other parties oppose the cap proposed in the Settlement Agreement, arguing that it doesn't exempt enough load, and seek to extend exemptions from the DWR forward charges even further. These parties advocate exemption from cost responsibility charges based on the alleged adverse economic impacts that would discourage development of Customer Generation.[38] These parties argue that many Customer Generation projects would be uneconomical if the Settlement Agreement were adopted, and would thereby inhibit the Customer Generation industry. CLECA argues that impairment of incentives for Customer generation would adversely impact all electric customers in California by diminishing perhaps the best opportunity to add new generation resources and thereby avoid another power supply shortage.

A number of parties argue that the cap is unfair to smaller generators, and seek various exemptions from the cap based on public policy considerations.[39] AReM / WPTF, for example, recommends that new small cogeneration projects with a nameplate rating of five MW or less be exempt from the annual MW cap. AReM / WPTF express concern that the annual MW cap could be "eaten up" by a few large cogeneration projects and recommends that new small cogeneration projects with a nameplate rating of five MW or less be

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[38] *See, e.g.,* CMTA Comments; Districts Comments; SCAQMD Comments.

[39] *See, e.g.,* Districts Comments; AReM / WPTF Comments; Capstone Comments; CPA Comments; CEERT Comments; CALSEIA Comments; SCAQMD Comments.

excluded from the annual megawatt cap.[40] This concern is heightened by the provision of the Settlement Agreement that sets aside ten percent of the annual cap for one specific customer.[41]

The CPA recommends that all small DG projects of one MW or less in size should be exempt from the need to qualify under the annual MW cap on departing load exempted from CRS for CDWR's ongoing costs, and, instead, should be automatically exempt from such charges.[42]

CPA also recommends that zero, near-zero and low-emission (ultra-clean) DG technologies be exempt from paying tail CTC and costs in SCE's PROACT.[43] Similarly, the South Coast Air Quality Management District (District) seeks exemption for small, ultra-clean DG of five MW or less in size from all cost responsibility surcharges.[44] The Center for Energy Efficiency and Renewable Technologies (CEERT) also calls for the exemption of ultra-clean DG without regard to the MW cap,[45] as does Capstone Turbine Corporation (Capstone).[46]

Public Utilities Code Section 353.2(a) defines "ultra-clean and low-emission distributed generation" as any electric generation technology that

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40 AReM / WPTF Comments, pp. 2–8.

41 AReM / WPTF Comments, Appendix A, ¶ 1.a.

42 CPA Comments, filed Oct. 21. 2002, p. 1.

43 CPA Comments, p. 2.

44 SCAQMD Comments, filed Oct. 31, 2002, p. 2.

45 Ex. 16, at p. 2 (CEERT (Starrs)). CEERT is a non-profit coalition of environmental and public interest groups, renewable energy providers, green energy marketers and energy efficiency technology companies founded in 1990.

46 CEERT Comments, filed Oct. 31, 2002, pp. 4-6.

commences its initial operation between January 1, 2003, and December 31, 2005, and:

> "produces zero emissions during its operation or produces emissions during its operation that are equal to or less than the 2007 State Air Resources Board emission limits for distributed generation, except that technologies operating by combustion must operate in a combined heat and power application with a 60-percent system efficiency on a higher heating value."

Section 353.2(b) also states: "In establishing rates and fees, the [C]ommission may consider energy efficiency and emission performance to encourage early compliance with air quality standards established by the State Air Resources Board for ultra-clean and low-emission distributed generation."

CEERT argues that imposing CRS on emerging, ultra-clean distributed generation will impair the ability of these technologies to compete against dirtier, gas-fired forms of distributed generation, such as single-cycle microturbines and diesel generators.[47] CEERT claims that it would be contrary to legislative intent and state policy to apply excessive charges to this type of DG. CEERT argues that the Settlement Agreement will inappropriately penalize customers for choosing to operate zero, near-zero and low-emission DG.

CEERT proposes a three-tiered approach to encourage use of and achieve the greatest environmental benefit from this electric generation technology: (1) a minimum of several hundred new MW of zero, near zero and low-emission distributed generation technologies should be brought on-line by 2005 (2) discounted fees should be applied to these technologies based on performance; and (3) net metered solar and biogas installations should be

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[47] Ex. 16, at p. 3 (CEERT (Starrs)).

exempted from CRS entirely, primarily due to practical difficulties in implementation.

CEERT expresses concern that the CARB may be pressured to roll back recently adopted DG emissions standards unless a minimum of several hundred MWs of DG, which meet the 2007 standards, are installed by 2005.[48] CEERT, therefore, recommends that the Commission act to encourage the addition of as much on-line capacity of this type of DG by 2005. The structure for implementing this goal should include first-in-line priority to entering the system over other dirtier types of technologies, exempting these clean technologies from any potential future cap(s) on DG, and possibly also targeting MW goals and an annual ramp-up schedule.

The CalSEIA recommends a blanket exemption for DL served by distributed solar generation.[49] CalSEIA opposes any surcharges on customers investing in solar generation facilities beyond otherwise applicable rates for net power drawn from the grid.[50] CalSEIA argues that imposition of surcharges beyond those provided for in otherwise applicable tariffs for net power would erect new and potentially very significant barriers to further development of clean, renewable generation, and would be inconsistent with numerous policies and programs established by the Legislature, the CEC, and the Commission.

c) Position of SDG&E and ORA

ORA opposes granting any exemptions from cost responsibility surcharges for Customer Generation based on claims that incentives should be

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[48] Exhibit (Ex.) 116 (CEERT (Starrs)). See also, California Code of Regulations, Title 17(3)(1)(8), Article 3 (Distributed Generation Certification Program).

[49] CalSEIA Comments, Oct. 31, 2001.

[50] Exs. 117, 118, and 119 (California Solar Energy Industries Association (CalSEIA) (Starrs and Shugar).

provided to promote growth of renewable and low emission customer generation technologies. SDG&E opposes recognizing any such exemptions with respect to the DWR Bond Charge, but favors recognizing such exemptions with respect to forward-looking DWR power charges.

C. SCE'S Historical Procurement Charge

1. Parties' Positions – Pre-Settlement

In its opening testimony in this phase of the proceeding, SCE proposed to apply the HPC to DL customers on the same basis as was adopted for DA customers in D.02-07-032. The HPC provided for recovery of the costs in SCE's PROACT. Because DL customers affected by SCE's HPC proposal did not receive adequate notice, SCE agreed to withdraw its testimony in the A.98-07-003 proceeding proposing application of the HPC to DL customers. The HPC adopted in D.02-07-032 thus only applies to DA customers.

SCE argues that because the scope of this proceeding has been expanded to include recovery of costs from DL customers, it should be allowed to renew its proposal for application of the HPC to DL customers.

Real Energy and the Joint Parties argue that affected DL parties still have had no opportunity to comment or to provide input regarding SCE's HPC because DL issues were specifically excluded from the A.98-07-003 proceeding where the HPC was litigated and adopted. These parties contend that SCE has offered no evidence as to what, if any, of these costs may have been incurred by DL customers. If the Commission chooses to impose an SCE HPC on DL customers, however, the parties argue that such charge should only be considered for DL customers that leave the utility system after a final decision is issued in this proceeding. Moreover, the parties argue that no HPC should be imposed against such DL customers absent a showing that some portion of the PROACT balance is attributable to them.

CLECA acknowledges that "departing load customers should pay for their share of these costs by both their serving utility and the DWR" and therefore agrees that "the HPC may be appropriate."[51] CPA maintains that new qualifying Customer Generation falling within the annual MW caps should also possibly be exempt from SCE and PG&E's historic charges, citing the "state's expressed need to increase energy supply resources in California and the Commission's recognition of "distributed generation as a desired new resource."[52] Similarly, Capstone argues that small clean distributed generation should be exempted from utility historical costs based on the "offsetting benefits" of such generation.[53]

2. Proposed Settlement Treatment

The Settlement Agreement proposes that DL customers pay a share of SCE's HPC as prescribed in Section 7.1, based on a customer-specific analysis of the customer's contribution to the utility shortfall and the revenues that customer has already contributed toward recovery of those costs. The customer-specific analysis is based on the methodology specified in Appendix B of the Settlement Agreement. The calculation will compare the generation revenue received since May 2000 with costs incurred to serve the customer's documented consumption. The customer's cost responsibility will be determined by multiplying the customer's cumulative undercollection as of August 31, 2002, by the ratio of the starting balance of the costs in SCE's PROACT. The HPC to be assessed upon a customer's departure will equal the difference between the customer-specific HPC obligation at the start of the recovery period and the

[51] CLECA Comments, p. 4.

[52] CPA Comments, p. 2, *citing* D.02-10-062.

[53] Capstone Comments, pp. 6–7.

customer's total contributions to PROACT. This obligation will be corrected by the projected ratio of load to be served by Customer Generation to the pre-departure load.

D. Ongoing Transition Costs

1. Background

At issue are also the recovery of certain utility-related above-market costs assignable to DL served by Customer Generation. These costs relate to what are commonly called "tail" competition transition charges (CTC). CTC was originally envisioned as a byproduct of a industry restructuring program to provide for a competitive environment pursuant to legislative enacted in AB 1890. As originally envisioned, AB 1890 was to provide for an "orderly" transition to a competitive generation market which would be completed by March 2002. (§ 330.)

Public Utilities Code Section 369 provides that "[t]he commission shall establish an effective mechanism that ensures recovery of transition costs referred to in Sections 367, 368, 375, 376, and subject to the conditions in Sections 371 and 374, inclusive, from all existing and future consumers in the [utility's] service territory … ." Section 368(a) prescribes that electric rates would remain fixed at the June 10, 1996 levels, through March 31, 2002 at the latest except for residential and small commercial customer rates which were reduced by 10%. These frozen rates, along with a residual component of rates specifically delineated as the CTC, provided an opportunity for the utilities to accrue the revenues to collect "transition costs."

D.00-06-034 in A.99-01-016 adopted a methodology for allocating ongoing transition costs after the end of the AB 1890 rate freeze, but did not address how such amounts were to be calculated. The decision directed PG&E to implement CTC through its Phase 2 general rate case (A.99-03-014) and SCE through A.00-01-009. Since these two proceedings have been suspended or otherwise terminated, the determination of an ongoing "tail" CTC applicable to DL customers remains to be addressed in this proceeding.

2. Parties' Positions – Pre-Settlement

Certain parties opposed any charge to DL customers for ongoing above-market utility portfolio costs.[54] Various parties representing Customer Generation interests argue that while AB 1890 gave the Commission limited authority to impose certain surcharges on direct access customers, it specifically exempted onsite customer generation from these charges. (§ 372 and 374.) In addition, even where AB 1890 gave the Commission authority to impose surcharges, they claim that most were subject to a statutory sunset date of December 31, 2001.

CLECA argued that "it does not make sense" that utility tail CTC should continue to apply to departing load, on the premise that "the entire concept of tail CTC has lost any meaning in the wake of the Legislature's passage of AB 6X and the return to cost-of-service ratemaking for utility generation.[55]" Other parties argued in favor of similar exemptions from "tail" CTCs.[56]

The utilities stated, in contrast, that some measure of ongoing utility portfolio costs must be imposed on DL.[57] PG&E proposed the continuation of

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[54] *See, e.g.,* Supplemental Opening Testimony of Maric Munn and Mark Gutheinz on Behalf of the University of California and California State University Relating to Cost Responsibility for DL Customers, Ex. 125, at 9-10; Reply Testimony of Steven A. Greenberg on Behalf of RealEnergy, Inc. and Joint Parties Interested in Distributed Generation / Distributed Energy Resources, Ex. 83, at 9-11.

[55] CLECA Comments, p. 5.

[56] *See* CPA Comments, p. 2; Capstone Comments, p. 7; CEERT Comments, p. 5; CMTA Comments, p. 2; Eastside Comments, p. 2.

[57] *See, e.g.,* SCE Proposal for DL Non-Bypassable Charges (Exit Fees), Ex. 76, at 15.

the "tail CTC" under AB 1890.[58] SCE proposed that the Commission "establish a nonbypassable charge to recover the above-market costs of SCE's portfolio of retained generation and energy contracts." Unlike the "tail CTC" in AB 1890, SCE's proposed measure would have been unlimited both in term and in the resources that could be included in the ongoing charge. SCE argued that the "tail CTC," a more limited measure of ongoing utility portfolio costs, combined with a continuing cogeneration exemption, represents a reasonable compromise of positions in the interests of bundled ratepayers, the utilities and DL customers. SDG&E is uniquely situated with respect to its recovery of CTC because it has ended its rate freeze. SDG&E argued that the Commission, in this proceeding, should expressly authorize the continued collection of SDG&E's CTC pursuant to existing tariff.

3. Proposed Settlement Treatment

The Settlement Agreement proposes that all DG shall pay a provision for tail CTC, except those categories of load exempted from such a charge pursuant to any statute as of the date of execution of the Settlement Agreement. The eligible costs will be limited to those cost categories defined in Public Utilities Code Sections 367(a)(1)-(6).[59] The tail CTC would be determined as the above-market portion of the applicable CTC-related costs based on the market benchmark adopted in D.02-11-22 regarding DA CRS.

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[58] *See* PG&E Order Instituting Rulemaking Regarding the Implementation of the Suspension of Direct Access Pursuant to AB 1X and Decision 01-09-060 Prepared Testimony, Ex. 87 (PG&E / Keane, Opening Testimony) at 2-3 to 2-7.

[59] The specific eligible cost categories covered by the CTC are: (1) employee-related transition costs through December 31, 2006; (2) power purchase contract obligations for qualifying facilities and purchase power agreements signed before December 20, 1995; (3) nuclear incremental cost incentive plan for the San Onofre Nuclear Generating Station, provided that the recovery shall not extend beyond December 31, 2003.

The CTC revenue requirement would be derived for the qualifying facility and power purchase agreement portfolio by multiplying the above-market per-mWh charge times forecasted consumption in the portfolio. The total tail CTC revenue requirement would constitute the above-market portion of the QF and power purchase costs, plus the employee-related transition costs and, in the case of SCE, any costs associated with the nuclear incremental cost incentive plan. The revenue requirement, divided by the total applicable load, would yield the CTC rate. The total applicable load would include bundled, direct access, and DL customers not otherwise exempted pursuant to § 372 and / or 374.

E. Miscellaneous issues

1. Definition of Customer Generation and Departing Load

In their Comments, CHW requests "clarification from the settling parties and / or the Commission that if new or incremental customer load of an existing customer is wholly or partially met through a 'direct transaction' as defined by Public Utilities Code Section 331(c), and the new or incremental load does not require the use of utility transmission or distribution facilities, the load would not be treated as departing load responsible for the [DWR] bond charges."[60]

The Commission has previously considered this issue in the context of CTC, for new load served by a Customer Generation unit but taking standby service from a utility. Section 369 of the Public Utilities Code states that such CTC "shall not be recoverable for new customer load or incremental load of an existing customer where the load is being met through a direct transaction and the transaction does not otherwise require the use of transmission or distribution

[60] CHW Comments, pp. 2–3.

facilities owned by the utility." In A.96-08-001 et al., the Commission considered whether taking standby service from a utility meant that the new or incremental load was "otherwise requiring" use of the utility's transmission or distribution facilities, and in D.98-12-067 the Commission implemented a "physical test" to make such a determination.[61] If a Customer Generation unit serving new or incremental load can pass the physical test, the load is not considered to be departing, and is not obligated to pay CTC.

The Joint Settling Parties' intention is that this same physical test, currently embodied in the utilities' tariffs, also be used to determine whether new or incremental load is considered to be "departing" for purposes of assessing CDWR Bond and Forward charges.

Eastside argues that the definitions of Customer Generation and DL in Sections 3.11 and 3.12, respectively, are too narrow and should be expanded to include any public entity, including a Joint Power Authority. They further argue that a new Section 3.22 should be added to define the term "utility grid" to reflect their proposed modifications to Sections 3.11 and 3.12.[62] The Joint Settling Parties oppose these proposed modifications, arguing that the definitions of "Customer Generation" and "Departing Load" were matters of much discussion and debate during settlement negotiations. The Joint Settling Parties agreed that, for the sake of clarity and ease of administration, the Settlement Agreement would conform as closely as possible to the utilities' tariff definitions of those terms. Public entities, such as Joint Power Authorities, that could potentially

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[61] The physical test "requires that new or incremental customer load be able to be 'islanded' to demonstrate that the direct transaction does not require the use of the utilities' systems." (D.98-12-067, mimeo., p. 24). Resolution E-3600, dated March 13, 1999, approved tariff language for the three utilities implementing the physical test.

[62] Eastside Comments, pp. 3–6.

serve numerous customers by wheeling power from a generator over utility distribution wires, fall outside the definitions contained in the utilities' tariffs and agreed to in the Settlement Agreement. Even if particular generating arrangements currently held by public entities do not currently sell power to retail end-use customers, the potential does exist for them to do so. Applicability of fees to such arrangements would be beyond the scope of the issues addressed in this phase of this proceeding. Our intent in this decision is to focus on customer generation that is primarily used to serve on-site needs. Thus, we decline to adopt the definitional and tariff modifications requested by Eastside.

In its Comments, DWR also expresses concern about the definition of "Departing Load" based on the exclusion of "new load that is served by Customer Generation and that does not rely on IOU transmission or distribution facilities."[63] The Joint Settling Parties indicate that they sought to conform the Settlement Agreement's definition of "Departing Load" as closely as possible to the utilities' tariff definitions. The utilities' current tariff definitions of "Departing Load" are based, in substantial part, on Public Utilities Code Section 369, as previously discussed. To the extent that so-called "islanded" Customer Generation customers are exempt from CTC, the Joint Settling Parties agree that they should also be exempt from DWR charges.

2. Biogas Digesters Exceptions to CRS

AECA supports the Settlement Agreement but is confused as to why Section 4.3 reserves the right of parties to oppose any proposal for an exemption from DWR Historical Costs and Forward Costs, or Historical Procurement Charges for eligible biogas digester customer-generators, as defined in § 2827.9.[64]

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[63] DWR Comments, p. 1.

[64] AECA Comments, p. 1.

According to AECA, eligible biogas digester customer-generators are exempt from departing load charges, and therefore no new or additional charges that would increase an eligible biogas digester customer-generator's charges beyond those of other customers in the same rate class may be included. Similarly, CEERT argues that the Legislature, in passing Assembly Bill No. 2228 ("AB 2228"), (Stats. 2002, ch. 845), "specifically considered and elected to exempt biogas (also known as biodigester) projects from any net metering or other charges for departing the system," and that biogas generators "should be exempted from any fees imposed by this proceeding."[65]

The Joint Settling Parties agree with AECA's and CEERT's interpretation of AB 2228 and express their intention that tariffs implementing AB 2228 be filed consistent with that interpretation.

3. Implementation of Surcharges on Net Metering Customers

Both CalSEIA and CEERT argue that the Settlement Agreement fails to address the practical problems associated with imposing surcharges on net metering customers under Assembly Bill No. 58 ("AB 58"), Stats. 2002, ch. 836.[66] Section 4.3 of the Settlement was intended to reserve resolution of the issues associated with AB 58 prior to the utilities' filing of implementing tariffs. Pursuant to Section 4.3, parties reserve the right to make whatever arguments they wish regarding the applicability and implementation of DWR and utility charges to net metered customers under AB 58.

[65] CEERT Comments, pp. 6–7.

[66] CalSEIA Comments, p. 5; *see also Id.*, pp. 20–24; CEERT Comments, p. 6.

V. Discussion of Contested Issues

A. Fundamental Issues

We begin our discussion by addressing two fundamental issues: our legal authority to impose cost responsibility surcharges (CRS) on customer generation, as well as the disposition of the settlement agreement.

1. Legal Authority for Imposing Cost Responsibility Surcharges

Any charges we impose in this decision must be consistent with the law. Various parties representing DL interests generally argue that the Commission lacks jurisdiction over the right to engage in Customer Generation and the charges associated with CG. EPUC / KCC / GAG also claimed that such charges are prohibited by law and contrary to principles of cost causation. Various parties also claimed that explicit State and federal policies encouraging the development of Customer Generation would be frustrated by the imposition of any CRS on DG load.

We conclude that the Commission has the requisite legal authority to authorize and implement cost responsibility surcharges on Customer Generation load. This authority is clearly set forth in Assembly Bill No. 117 ("AB 117"), which clarified the Legislature's intent concerning the implementation of AB 1X, and the recovery of DWR-related costs from retail end-use customers. (AB 117, Stats. 2002, ch. 838).[67] AB 117, which was signed into law September 24, 2002, the Legislature enacted Public Utilities Code Section 366.2(d)(1) which makes all end-use customers who took bundled service on or

[67] The Commission's authority to adopt and allocate CRS to Customer Generation load is also found in AB 1X concerning the obligations to retail end-use customers for DWR costs, and our broad authority to regulate "to do all things…which are necessary and convenient in the exercise of such power and jurisdiction," under Public Utilities Code Section 701. (See discussion, D.02-11-022, pp. 11-13 (slip op.).)

after February 1, 2001 responsible for a fair share of costs incurred by DWR. This statutory provision provides:

> "It is the intent of the Legislature that each retail end-use customer that has purchased power from an electrical corporation on or after February 1, 2001, should bear a fair share of the [DWR's] electricity purchase costs, as well as electricity purchase contract obligations incurred..that are recoverable from electrical corporation customers in commission-approved rates. It is further the intent of the Legislature to prevent any shifting of recoverable costs between customers." (Pub. Util. Code §366.2, subd.(d)(1).)

Thus, AB 117 gives the Commission the authority for imposing a "fair share" of cost responsibility on customers, including Customer Generation Departing Load, that took utility service on or after February 1, 2001. The determination of what the "fair share" should be is left to the Commission's determination in its exercise of this authority.

However, in addressing the energy problems confronting California which resulted in the enactment of AB 1X, the Legislature also enacted several laws with the legislative objectives to promote investment and construction of renewal energy resources, diversify California's energy resource mix, stabilize California energy supply infrastructure and produce economic and environmental benefits. (See generally, Assembly Bill No. 29, ("AB 29"), Stats. 2001, ch. 8, enacting Public Utilities Code Sections 2827, 2727.4 and 2827.7 (net energy metering for eligible customer-generators program); SB 28X, Stats. 2001, ch. 12, enacting Public Utilities Code Section 353.1, et seq. (distributed energy resources); Senate Bill No. 1038 ("SB 1038"), Stats. 2002, ch. 515, adding Public Utilities Code Section 353.2 and amended Public Utilities Code Section 383.5 (increasing the amount of renewable electricity generated in California); AB 58, Stats. 2002, ch. 836, amending Public Utilities Code Sections 2827 and 2827.7, and added Sections 2827.8 (operation and development of emerging renewable resource technologies and net energy metering); AB 2228, Stats. 2002, ch. 845, enacting Public Utilities Code Section 2827.9 (net energy metering for eligible biogas digester customer-generators).)[68]

In implementing AB 117, we are cognizant that our implementation should not be in conflict with other statutes, including the legislative intent codified in these statutes, that were enacted at the same time and in response to the electricity problems confronting California. It is important that the Commission's determinations regarding its implementation of AB 117 should be in harmony with those other statutes the Legislature enacted in response to the energy problems confronting California. Thus, our interpretation in today's decision reflects our harmonizing of the AB 117 and these statutes.[69] Accordingly, we have provided for CRS exceptions as specified in today's decision.

For example, Public Utilities Code Section 353.2 provides:

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[68] AB 29 was signed into law on April 11, 2001 and SB 28X was signed into law on May 22, 2201. AB 1038 became law on September 12, 2002. The Governor signed AB 58 and AB 2228 into law on September 24, 2002. This is the same date that AB 117 was signed into law.

[69] When confronted with an apparent conflict between statutes, the rules of statutory construction requires that the statutes be harmonized so as to give effect to the such statutes insofar as possible. (See e.g., Waters v. Pacific Telephone Company (1974) 12 Cal.3d 1, 11; Rubin v. Green (1993) 4 Cal4th 1187, 1201; San Diego Gas & Electric Company v. City of Carlsbad (1998) 64 Cal.App.4th 785, 793.) The interpretations of the statutes should also be guided by consideration of the statutes in context of the statutory framework, including when the statute was enacted and for what public purpose. (See e.g., Neumarkel v. Allard (1985) 163 Cal.App.3d 457, 461-462; see also, Moyer v. Workmen's Compensation Appeals Board (1973) 10 Cal.3d 222,230)

> "In establishing rates and fees, the commission may consider energy efficiency and emissions performance to encourage early compliance with air quality standards established by State Air Resources for ultra-clean and low-emission distributed generation." (Pub. Util. Code § 353.2, subd. (b).)

Thus, despite apparent contrary language in AB 117, we have harmonized Public Utilities Code Section 366.2(d) with Public Utilities Code Section 353.2(b) to permit an exception for the payment of CRS for load involving ultra-clean and low-emission distributed generation.

In sum and unless otherwise excepted, Customer Generation load must be held responsible for a fair share, as determined by this Commission, of the DWR revenue requirements. To the extent that customers departed from bundled utility service to be served by Customer Generation after DWR began buying power on January 17, 2001, such customers consumed power that had been purchased by DWR. The DWR costs for which customers bear responsibility include both previously incurred costs as well as an ongoing cost component. We address the more specific applicability of each respective charge in our discussion below.

2. Disposition of the Settlement Agreement

The Settlement Agreement is sponsored by parties representing a range of interests but is not supported by all parties. Certain provisions are opposed by a number of parties, including ORA, SDG&E, and various parties representing Customer Generation interests.

We appreciate the fact that the Settlement reflects a broad range of divergent interests, including those of the utilities (i.e., PG&E and SCE) and of residential customer representatives (i.e., TURN). The interests of commercial and industrial customers who have developed, or are developing, Customer Generation projects are represented in the Settlement by parties such as BOMA, EPUC, and CIPA, among others. The interests of developers of Customer Generation are represented in the Settlement by Clarus Energy Corporation and Real Energy, among others. The interests of the State of California as a large energy consumer are represented by UC / CSU. The CEC, as a joint settling party, also brings its broad perspective on the State's energy future.

In addition, we have also reviewed and considered the objections of those parties that did not join in the Settlement, including AReM / WPTF, CEERT, CPA, CalSEIA, and the Districts. We recognize that these parties disagree with certain aspects of the results reached in the Settlement. As discussed above in detail, we find merit in the objections raised by these parties, particularly with regard to the Settlement's inconsistency with Legislative and Commission policy direction.

As a basis for reviewing the Settlement, we are guided by the Commission's Settlement Rules set forth in the Rules of Practice and Procedure, Article 13.5: "Stipulations and Settlements." Rule 51.1(e) provides that the Commission must find a settlement, whether contested or uncontested, to be "reasonable in light of the whole record, consistent with the law, and in the public interest" before it may approve a settlement. As we explained in D.96-01-011:

"[W]e consider whether the settlement taken as a whole is in the public interest. In so doing, we consider individual elements of the settlement in order to determine whether the settlement generally balances the various interest at stake as well as to assure that each element is consistent with our policy objectives and the law." (<u>Re Southern California Edison Company</u>, [D.96-01-011] 64 Cal. P.U.C.2d 241, 267, quoting <u>Re Natural Gas Procurement and System Reliability Issues</u> [D.94-04-088, p. 8 (slip op.)] (1994) 54 Cal. P.U.C.2d 337, 343.)

Since the Settlement before us is contested, we take note of the approach followed regarding a contested settlement in D.01-12-018. There, we stated that when a contested settlement is presented to us where hearings have been held on the contested issues, we are free to consider such settlements under Rule 51.1(e) or as joint recommendations. Evidentiary hearings were held on the contested issues in this proceeding, although various parties elected to waive or curtail cross-examination. Nonetheless, the underlying testimony was received into evidence, and forms an independent basis against which to evaluate the reasonableness of the Settlement Agreement.

Under Rule 51.1(e), we may reject a settlement if one or more of its elements is not consistent with our policy or the law, without elaborate examination of all the elements and without dealing with each contention of each party. We recognize that considerable time and effort have been expended preparing a settlement such as this one, which is sponsored by a large number of diverse interests. Nevertheless, we cannot abandon our regulatory obligations in favor of a negotiated outcome.

We believe the Settlement Agreement is inconsistent with Legislative direction contained in several bills including SB 28X (Stats. 2001, Ch. 12), AB 970 (Stats. 2000, Ch.329), and SB 1038 (Stats. 2002, Ch. 515), which indicate a policy preference for customer generation in general, as well as clean CG in particular. Further, we believe giving customers preferential access to ultra-clean and low-emission generation serves the public interest in general, and not just the particular interests of the individuals who choose to install customer generation. In fact, as noted above, there are a number of incentive programs in place, overseen by both this Commission and the CEC, to encourage installation of customer generation as in the public interest. Though we appreciate that the Settlement Agreement attempts to balance these objectives, we do not believe it does so in a manner that is consistent with the public interest. We therefore reject the Settlement Agreement as inconsistent with Legislative and Commission policy, as well as contrary to the public interest.

Upon rejection of a settlement, the Commission may take various steps, including the following options, as set forth in Rule 51.7:

1. Hold hearings on the underlying issues, in which case the parties to the stipulation may either withdraw it or offer it as joint testimony,

2. Allow the parties time to renegotiate the settlement,

3. Propose alternative terms to the parties to the settlement which are acceptable to the Commission and allow the parties reasonable time within which to elect to accept such terms or to request other relief.

In this instance, the Settlement Agreement has assisted us considerably in defining the issues and coming to our decision, as we discuss in considerably more detail below. We have also already held hearings on the underlying issues to establish the factual record for our decision-making. The majority of the choices we make in this decision are questions of policy and not fact, however. Thus, on the basis of the entire record before us, we reject the Settlement Agreement. All parties have had the opportunity to comment on our resolution of the contested issues as part of their comments on this decision.

B. Applicability of CRS Components to Customer Generation Departing Load

Since we have chosen to reject the Settlement Agreement, we must deal with the applicability of each of the surcharge categories (DWR bond charges, DWR power charges, SCE's HPC, and tail CTC) to a variety of types of customer generation. In our general discussion above rejecting the Settlement Agreement, we noted the Legislature has expressed a policy preference, as codified in recently enacted statutes (see discussion, infra) for certain types of customer generation, including ultra-clean and low-emission, as well as net metered systems. We also note that several parties to this proceeding refer to our obligation to address valuation of distributed generation benefits and costs both to the overall electric system as well as to individual customers. We intend to address this question more fully in a successor rulemaking to R.99-10-025, as stated in D.03-02-068. On the basis of the policy preferences already articulated by the Legislature, as codified in recently enacted statutes, and by this Commission, however, we believe that there is sufficient policy basis to believe that customer generation confers a positive public benefit. Therefore, and consistent with these legislative policy directives, and in support of our policy preferences, we believe that we should apply CRS components differentially to the following three distinct categories of customer generation:

1. Clean systems with a capacity of under 1 MW (including-net metered systems)
2. Systems with a capacity of more than 1 MW that also meet the criteria established in Public Utilities Code Section 353.2 ("ultra-clean and low-emission distributed generation")
3. All other types of customer generation

We discuss these categories, the reasoning behind them, and the applicability of different CRS components to them, in more detail below. We also address the concept of applying a MW cap on exemptions, above which all CRS component charges will apply. Finally, we address several miscellaneous categories of customer generation that are categorically exempted from any CRS.

1. Clean Customer Generation Systems Under 1 MW

Although the parties to the Settlement Agreement chose not to deal with issues related to net metering due to the difficulty in reaching consensus, we actually believe that this group of customer self-generation represents the category that is simplest to handle. Public Utilities Code Section 2827, which establishes the net metering program, prohibits any requirement for net-metered customers to install a second meter to measure the gross output of self-generation. Thus, by definition, it would be impossible for us to impose CRS charges on the gross output of a net-metered system representing departing load. Also by definition, customers participating in net metering will pay all applicable charges on the net portion of their energy usage just as any other bundled customer does. We agree with CEERT and other parties who argue that the costs of attempting to measure and charge CRS to the gross output of net-metered systems could outweigh any potential benefits (in the form of collections of CRS). Thus, all net-metered departing load shall not be required to pay any cost components of the CRS.

Though one of the eligibility criteria for the net metering program is that the customer generation system be under 1 MW in size, not all CG in this size category is net metered. For example, a number of installations of solar photovoltaics are not net metered. We believe, therefore, that certain other clean customer generation in this size category should be treated similarly regardless of its net metering status. In particular, both the CPUC and the CEC offer financial incentives from various funding sources to encourage installation of clean self-generation. The offering of a financial incentive clearly indicates a policy preference designed to encourage the installation of such systems. We intend to continue offering these types of systems a preference in order to encourage their installation. Therefore, if a system is under 1 MW in size and eligible for participation in either the CPUC's self-generation program or a CEC program, we will also provide an exception from payment of the full fair share for that system, and therefore the departing load it represents, from any requirement to pay any portion of the CRS.[70]

We recognize that the CPUC self-generation incentive program allows eligible systems up to 1.5 MW in size, while only offering financial incentives for the first 1 MW. We do not revise our exceptions to the CRS created in this decision to include 1.5 MW, as suggested by several parties including Clarus Energy. Instead, we continue to believe that a 1 MW size limit is appropriate for exceptions to CRS, because this is the size limit created by the Legislature in Public Utilities Code Section 2827. We maintain this size threshold to be consistent with the net metering program.

We also state our intent to revisit the 1 MW limit for exceptions to the CRS no later than three years from the date of issuance of this decision, in order to take into account any technological advances or economies of scale in customer generation production and sale.

If the CEC or CPUC incentive programs are discontinued in the future, we will reconsider tying continuing exceptions to the CRS to those programs at that time. Although the CPUC's self-generation program is currently set to expire on December 31, 2004, it is possible that we will extend the program, and today's decision neither addresses or prejudges any issues related to this program at this time.

Further, in response to comments, we indicate our desire to revisit and potentially modify the eligibility requirements for our self-generation

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[70] We also note, in response to comments from several parties, that systems up to 1.5 MW in size are eligible for inclusion in the CPUC self-generation program, but that financial incentives are only offered for up to 1 MW of capacity. However, we clarify that for purposes of this decision, we will only provide exceptions to the CRS for up to 1 MW of capacity. Thus, to gain a total exception to the CRS, a system must be under 1 MW and be qualified for inclusion in the self-generation program.

incentive program in a new distributed generation rulemaking as indicated in D.03-02-068. In particular, we would like to consider increasing the efficiency requirements associated with any systems receiving incentives that generate power through combustion with waste heat recovery. Although we cannot make any revisions to the program in this decision since these issues were not addressed in this proceeding, we signal our intent to examine these issues in our new distributed generation rulemaking.

Also in response to comments, we clarify that the exception to the CRS granted for these types of technologies includes no requirement to pay SCE's HPC, as well as any potential HPC that may be requested or granted in the future for PG&E and / or SDG&E.

Also in comments, PG&E and SCE argue that Public Utilities Code Section 2827(l) requires the Commission to impose DWR costs on net metering customers. They claim that our exception for net metering would be in violation of this statute. We disagree. Public Utilities Code Section 2827 (l) requires that net metering customers pay "nonbypassable" fees, including both bond charges and power charges. By definition, net metering customers do not bypass either the DWR bond charges, or power charges, since they continue to pay these charges based on their net energy consumption. We believe our interpretation in this decision is consistent with these provisions of Public Utilities Code Section 2827 (l).

Finally, we add a requirement that the utilities report to the Energy Division, and the CEC on a quarterly basis, the amount of customer self-generation installed in this category.

2. Ultra-Clean and Low-Emission Systems over 1 MW

Public Utilities Code Section 353.2 gives us explicit authority to consider the emissions and energy efficiency characteristics of customer generation in establishing rates and fees (subsection (b)). This code section also includes a definition of "ultra-clean and low-emission" distributed generation that meets the following criteria:

> "(1) Commences initial operation between January 1, 2003, and December 31, 2005.
>
> (2) Produces zero emissions during its operation or produces emissions during its operation that are equal to or less than the 2007 State Air Resources Board emission limits for distributed generation, except that technologies operating by combustion must operate in a combined heat and power application with a 60-percent system efficiency on a higher heating value."

As discussed in the previous section, any system that meets these criteria and is less than 1 MW in size will not be required to pay any CRS charges. For systems over 1 MW in size, however, we believe their scale dictates that they should be responsible for a fair share of the DWR bond charges. While making exception for systems under 1 MW from bond charges will not make a recognizable difference in collection amounts, collections on larger systems will have a noticeable impact. Therefore, we will require that systems meeting the Public Utilities Code Section 353.2 criteria which are over 1 MW in size pay the DWR bond charge.

In order to maintain the Legislature's and our policy for encouraging ultra-clean and low-emission customer generation in the public interest, we will make exception for these systems, so that they are not required to pay other portions of the CRS. In particular, ultra-clean and low-emission CG over 1 MW in size will not pay for DWR ongoing power costs, nor will they pay for SCE's HPC.[71] These systems should also still pay tail CTC,[72] to the extent that they are not otherwise exempted by Public Utilities Code Section 372 and / or 374.

We adopt the exceptions for this category based on the above policy directives and considerations discussed above, including the importance of encouraging the installation of these types of generation. We agree with CEERT that not requiring this CG to pay most portions of the CRS (except the DWR bond charge and tail CTC, where applicable) will help support meeting the CARB aggressive standards.

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[71] As in the previous section, in response to comments, we note that this exception to payment of SCE's HPC could also apply in the future to any potential HPC adopted for PG&E and / or SDG&E.

[72] We clarify that any tail CTC payments required by this decision are defined as in Public Utilities Code Section 367 (a) (1)-(6) and calculated as follows:

- The above-market portion or uneconomic portion of these contract costs will be calculated by comparing the weighted average cost of the qualifying facility and power purchase agreement portfolio, in $ / MWh, against the benchmark adopted in the direct access phase of R.02-01-011.

- A revenue requirement will be derived for the qualifying facility and power purchase agreement portfolio by multiplying the uneconomic portion ($ / MWh) times the forecast of MWh in the portfolio. A total "tail" CTC revenue requirement will be derived by adding the uneconomic portion of the qualifying facility and power purchase agreement revenue requirement to the employee-related transition costs and, in the case of SCE, any costs associated with the nuclear incremental cost incentive plan. The total "tail" CTC revenue requirement will be divided by the total applicable load to derive the CTC rate applicable to Departing Load. The total applicable load includes bundled, direct access, and Departing Load customers not otherwise exempted from ongoing CTC pursuant to statute or to this order.

- Any other charge established in the direct access phase of R.02-01-011 to recover the cost of above-market utility retained generation assets or power purchase obligations shall not be applied to Departing Load.

(definitions taken from the Settlement Agreement, Section 8)

We will, however, impose a cap on customer generation systems over 1 MW in size exempted from various portions of the CRS, as discussed in more detail in Section V.B.4 below.

3. Other Customer Generation

This category of customer generation includes any generation defined in this order that is not addressed in Section V.B.1 and V.B.2. This category does not include back-up generation or any diesel-fired customer generation. All generation addressed in this category, and in this decision, must meet best available control technology standards set by local air quality management districts and / or the California Air Resources Board, as applicable.

We will require any other customer generation departing load not discussed in sections V.B.1 and 2 above to pay all CRS components except the DWR ongoing power charges, up to a certain MW limit as discussed in Section V.B.4 below. Though we wish to support the option of customers to install self-generation, we generally wish to encourage more environmental forms of CG, as described above. Therefore, we do not find a policy justification for exempting CG that is not eligible under Public Utilities Code Section 353.2 from historic procurement charges or, under Public Utilities Code Sections 353.2, 372, or 372, from tail CTC. These systems will therefore be required to pay DWR bond charges, historic procurement charges, and tail CTC. The exception for DWR ongoing power charges is discussed in more detail in the following section.

In response to comments, we also wish to define more clearly the HPC that these types of systems should pay. As noted earlier in this decision, any discussion of HPC for PG&E and SDG&E is outside the scope of this decision. However, SCE HPC should be defined as follows (taken from Section 7.1 of the Settlement Agreement, as well as Appendix B):

- Customer generation departing load defined in this section of this decision that took direct access service at the time of the departure will continue to pay the HPC amounts authorized in D.02-07-032, or successor decisions. Any direct access customer that had load departing after March 29, 2002, but prior to the implementation of this decision, will be back-billed to July 27, 2002 at the 2.7 cents per kWh rate and will be responsible for the charges adopted in D.02-07-032, or successor decisions, on a prospective basis.
- The HPC responsibility for customer generation departing load defined in this section of this decision, that was receiving bundled service at the time of the departure, shall be computed on a customer-specific basis using the following methodology:
    - The generation revenues received from the customer since May 2000 shall be compared with the procurement costs incurred to serve the customer's recorded kWh usage. The procurement costs prior to January 17, 2001 shall be based on the Schedule PX prices. The procurement costs from January 17, 2001 through August 31, 2001 shall be based on the amounts in SCE's Energy Cost Accounting system as reflected in Schedule PE. The procurement costs for September 2001 forward shall be equal to the generation-related recoverable costs incurred on behalf of bundled service customers and reflected in SCE's Settlement Rate Balancing Account on a cents per kilowatt-hour basis.
    - A customer-specific HPC cost responsibility will be determined by multiplying the customer's cumulative undercollection on August 31, 2002, by the ratio of the starting PROACT balance to the

cumulative costs in SCE"s PROACT as verified by the Commission's Energy Division.

- The customer's monthly contributions to the PROACT will be calculated by subtracting the customer's monthly generation-related costs from the customer's monthly generation-related revenues.
- The customer's HPC obligation at the time of departure will be the difference between the customer-specific HPC cost responsibility at the beginning of the recovery period designated in the settlement agreement entered into by SCE and the Commission in Federal District Court Case No. 00-12056-RSWL, and the cumulative contributions to Surplus reflected in the PROACT, but never less than zero.
- The customer's HPC obligation will be adjusted by the estimated proportion of energy to be served by customer generation to the amount of energy used prior to departure.
- The customer's HPC obligation, at the customer's election, may be amortized and paid over a two-year period or in a single lump sum.

Also in response to comments, we wish to limit the amount of customer generation granted the exception for DWR ongoing power charges in this section. We are primarily concerned that setting no limit will result in installation of more non-renewable customer generation than renewable generation. Thus, we will limit the amount of installed MW capacity in this category to half of the cap defined in section V.B.4 below. We discuss this provision further in the next section.

4. Applicability and Administration of a MW Cap

We generally find the rationale behind setting a MW cap on the amount of customer generation not required to pay the DWR ongoing power charge portion of the CRS articulated in the Settlement Agreement to be reasonable. It is clear that DWR, when negotiating long-term power contracts, assumed that a certain amount of customer generation departing load would occur every year and therefore did not procure long-term power for that portion of the load. In fact, such an assumption is based on common sense, since utilities have always faced departing load in various forms, including that caused by an economic downturn, improvements in energy efficiency and building codes, as well as installation of self-generation systems. We therefore reject ORA's argument that no link has been established between assumptions of departing load and DWR's contract negotiations as irrelevant.

While we therefore agree with the overall rationale behind setting a cap to mitigate the risk of cost-shifting, we do not believe the assumptions included in the Navigant model utilized by DWR while negotiating long-term contracts could have been sufficiently precise to permit reliance on them to set an annual cap. We also believe that setting an annual cap would create unnecessary administrative complexity and market uncertainty. Therefore, we will simply rely on the DWR / Navigant model assumptions to set one overall cap of 3,000 MW (the approximate cumulative total (rounded) of DWR's annual assumptions over ten years).

We will apply this cap to all CG departing load. As under the Settlement Agreement, we request the assistance of the CEC in certifying systems as eligible under the cap. We will require the utilities to provide data and to cooperate with the CEC in this endeavor. In addition, we will request that the CEC provide an opportunity for public comment on the manner in which it will gather information, procedures for providing ongoing public notice of Customer Generation projects under development, and procedures for granting exempt status.

In response to comments, we also make several modifications and clarifications on our preferences for administration of the cap. First, we will not require systems described in Section V.B.1 above (small clean and net-metered systems) to apply for exemptions under the cap. Such systems should be tracked by the utilities and reported as described in this decision, and should count towards the cap, but should be automatically granted the CRS exceptions to their fair share as described in this decision.

To address concerns raised by the settling parties about potential cost-shifting to non-customer-generators if more systems are installed sooner than anticipated, as well as to mitigate concerns about too much non-renewable customer generation being installed, we add the following requirements:

- Other customer generation described in Section V.B.3 above should have the following limitations
  - — a cap of 600 MW before the end of 2004
  - — an additional 500 MW permitted until July 1, 2008
  - — a final tranche of 400 MW permitted after July 1, 2008

Adding these limitations causes us to reinstate the provisions of the Settlement Agreement that make special set-asides for UC / CSU. When we had an overall cap of 3000 MW, UC / CSU were confident that their projects would qualify for certain exceptions, but staggering our caps reintroduces uncertainty for UC / CSU's particular projects.

In particular, UC / CSU should be granted the following specific allocations:

- 10 MW by the end of 2004
- an additional 80 MW by the end of 2008
- an additional 75 MW after the end of 2008

Although ultra-clean and other types of customer generation will be granted exceptions to different portions of the CRS components, they will be counted under the MW cap on a first-come, first-served basis. Thus, ultra-clean and low-emission CG will receive a preference in terms of the portions of the CRS to be paid relative to other forms of CG, but will not be exempted from an overall cap on the amount of CG exempted from DWR ongoing power costs. Non-renewable CG, however, will be limited to a total of no more than 1500 MW, in these separate tranches, as discussed above.

Finally, once the 3,000 MW cap is reached, or the caps are reached on non-renewable CG, all additional CG departing load installed thereafter will pay all CRS components, including the bond charge, the DWR ongoing power charges, the HPC, and the tail CTC, as applicable.

We also request that the utilities report to the Energy Division and the CEC, and that the CEC track and report publicly, on a quarterly basis, the amount of customer generation installed under the caps identified above. The utilities should assist the CEC in this tracking and reporting. We will watch the progress of customer generation installations closely, and indicate our commitment to revisit the caps within three years or when 1000 MW of customer generation have been installed, whichever occurs first.

5. Other Excepted Customer Generation

We note that the parties to the Settlement Agreement stipulated that certain types of customer generation should be released from the DWR ongoing power charges, including:

- Existing load served by customer generation that departed utility service on or before January 17, 2001

- "Grandfathered" DL that becomes operational on or before January 1, 2003, or that submitted its CEQA application on or before August 29, 2001 and becomes operational on or before January 1, 2004.

We agree that those forms of departing load should be excepted from the DWR ongoing power charges. In addition, the first category should also be excepted from DWR bond charges, since that customer generation had departed before DWR began buying any power.

We also agree with the Settlement Agreement that it is reasonable to conform all of the definitions of departing load customer generation to utility tariffs, including the use of a "physical test" to determine whether new or incremental load requires the use of a utility's transmission or distribution facilities. In addition, because public entities such as joint power authorities fall outside the scope of the tariffs, they should be excluded for purposes of this order.

Finally, we agree with AECA and the Joint Settling Parties that, in accordance with AB 2228, eligible biogas digester customer generation are not required to pay CRS departing load charges.

VI. Tariff Filing Implementation

The utilities shall make compliance advice letter filings within ten business days of the effectiveness of this order, to amend their tariffs to implement the CRS on Customer Generation Departing load as provided for in this order. As noted previously, the bond charge component of CRS shall be implemented separately once this decision becomes final and unappealable pursuant to Section 4.3 of the Rate Agreement.

The advice letters implementing the CRS pursuant to this decision shall be effective on filing, subject to post-filing review by the Energy Division.

Remittances to DWR pursuant to the Servicing Agreements and Orders are to commence with the receipt of the applicable charges.

VII. Rehearing and Judicial Review

This decision construes, applies, implements, and interprets the provisions of AB 1X (Chapter 4 of the Statutes of 2001-02 First Extraordinary Session). Therefore, Public Utilities Code Section 1731(c) (applications for rehearing are due within 10 days after the date issuance of the order or decision) and Public Utilities Code Section 1768 (procedures applicable to judicial review) are applicable.

VIII. Comments on the Alternate Decision

The Proposed Alternate Decision of Commissioners Michael Peevey and Susan Kennedy was filed and served on parties on February 27, 2003. Comments on the Alternate Decision were due on March 6, 2003 with reply comments on March 10, 2003.

The following parties filed comments: the Settling Parties, the Districts, Cerritos, SCAQMD, AreM / WPTF, Clarus, Capstone, PG&E / SCE, TURN, EPUC / Kimberly Clark / Goodrich, ORA, DGS, CPA, SDG&E, CEERT, CEC, and CalSEIA. Reply comments were filed by the Setting Parties, CalSEIA, and the California Farm Bureau Federation. In response to these comments, we have made numerous clarifications and refinements throughout this decision. In addition, there were several comments made by the Settling parties on issues addressed nowhere in this decision. These include treatment of self-generation deferral agreements and treatment of any potential generator refunds. We clarify that nothing in this decision changes the terms of any self-generation deferral agreement, nor do we make any determinations about future disposition of any potential refunds ordered by the Federal Energy Regulatory Commission.

IX. Assignment of Proceeding

Carl Wood and Geoffrey Brown are the Assigned Commissioners and Thomas Pulsifer is the assigned ALJ in this proceeding.

Findings of Fact

1. D.02-03-055 determined that, as a condition of retaining the DA suspension as effective after September 20, 2001, a surcharge must be imposed on DA customers sufficient to prevent cost shifting to bundled customers as a result of DA migration between July 1 and September 20, 2001.

2. By ALJ ruling dated March 29, 2002, the scope of this proceeding was expanded to consider cost responsibility surcharges for "Departing Load" in order to prevent cost shifting to bundled customers.

3. Pursuant to Rule 51.1, a joint motion was filed for approval of a Settlement Agreement proposing disposition of various contested issues in this proceeding relating to cost responsibility surcharges applicable to Departing Load served by Customer Generation.

4. The Settlement Agreement is offered as an integrated document, and not as a collection of separate agreements on discrete issues. Each party has reserved the right to withdraw support of the Agreement if the Commission makes modifications or makes approval conditional upon modifications.

5. In October 2002, hearings were held on the issues underlying the Settlement Agreement. Parties also filed comments on the Settlement Agreement.

6. The CRS elements that are at issue for Customer Generation include DWR bond charges and ongoing power charges, "tail" CTC charges, and the historic procurement charge for SCE.

7. A number of parties raised concerns that adoption of a CRS on CG departing load will create economic disincentives to develop various forms of

alternative generation, as well as be contrary to Legislative and Commission policy.

8. The Legislature has recently enacted numerous statues codifying its policy preferences for customer generation, including AB 29, SB 28X, AB 58, SB 1038, and SB 2228.

9. The Commission (through the utilities) and the CEC, under Legislative direction, offer financial incentives for installation of certain forms of environmentally-preferable customer generation.

10. The provisions of the net metering program embodied in Public Utilities Code Section 2827 prohibiting a requirement for a second meter to measure gross electricity generation make it impossible to apply cost responsibility surcharges to the gross electricity usage of net metered customers. All other tariff components are applicable to the net consumption of such customers, which therefore assure a reasonable contribution to DWR costs.

11. The provisions for ongoing DWR power charges under the Settlement Agreement provides a reasonable recognition of forecasted Customer Generation that was taken into account in determining contractual commitments for the procurement of power by DWR during 2001.

12. The MW caps set forth in the Settlement form a logical basis for determining the exclusion of going-forward DWR costs applicable to Customer Generation.

13. DWR began procuring electricity on behalf of retail end use customers in the service territories of the California utilities: for PG&E and SCE on January 17, 2001, and for SDG&E on February 7, 2001.

14. AB 1X provides for DWR to collect revenues by applying charges to the electricity that it purchased on behalf of retail customers, as a direct obligation of DWR.

15. AB 117 requires that "each retail end-use customer that has purchased power from an electrical corporation on or after February 1, 2001, should bear a fair share of the DWR's electricity purchase costs, as well as electricity purchase contract obligations incurred…" but leaves the determination of "fair share" up to the discretion of this Commission.

16. Any customer generation departing load that departed prior to February 1, 2001 is exempt from any DWR bond charges or ongoing power charges.

17. Providing exceptions to some small and environmentally-preferable customer generation, as defined in this decision, that departed from utility service on or after February 1, 2001 from having to pay DWR bond charges and ongoing power charges is consistent with applicable provisions of AB 117 and AB 1X and the legislative policy directives in recently enacted statutes as specified in this decision.

18. The Commission has discretion to apply differentially a "tail" CTC, covering those cost categories defined in Public Utilities Code Section 367 (a)(1)-(6), consistent with Commission and legislative mandates for customers to bear their share of responsibility for the above-market component of utility purchased power and QF contracts.

19. The Commission has the discretion to apply a Historic Procurement Charge from Customer Generation differentially in the SCE service territory, covering a share of the costs authorized in D.02-07-032, as modified by D.03-02-035, and calculated as described in the text of this decision.

20. Granting exceptions to certain portions of the CRS for customer generation up to 3000 MW will not result in any cost-shifting among customers, since costs for those MW were not incurred by DWR.

Conclusions of Law

1. The Commission has broad authority under general provisions of Public Utilities Code Section 701 to regulate public utilities and to "do all things…which are necessary and convenient in the exercise of such power and jurisdiction."

2. The Commission has authority under AB 117 and AB 1X to impose CRS on Customer Generation Departing Load to recover DWR-related costs and to determine each customer's fair share of those costs.

3. Pursuant to AB 117, as codified in Public Utilities Code Section 366.2(d), AB 1X and Public Utilities Code Sections 701 and 366(d), as well as the provisions of D.02-02-051, the Commission has legal authority to apply DWR Bond Charges on Departing Load Customer Generation that departed from utility service after DWR began procuring power on behalf of retail utility customers.

4. Under Rule 51.1(e), the Commission must find a settlement, whether contested or uncontested, to be "reasonable in light of the whole record, consistent with the law, and in the public interest" before it may approve a settlement.

5. As prescribed in D.01-12-018, when a contested settlement is presented and where hearings have been held on contested issues, the Commission is free to consider such settlements under Rule 51.1(e) or as joint recommendations that may or may not be supported by record evidence.

6. As discussed in this decision, we reject the Settlement Agreement as inconsistent with Legislative and Commission policy, and contrary to the public interest, primarily due to its treatment of small and environmentally-preferable customer generation departing load.

7. It is reasonable and consistent with Legislative and Commission policy to provide an exception for customer generation under 1 MW in size and eligible

for either net metering, CPUC self-generation funding, or CEC financial incentives, from all CRS cost components. It is also reasonable to reevaluate this size cap within three years of the date of this decision, to take into account developments in technology and economies of scale.

8. The CPUC should revisit the eligibility criteria for its self-generation incentive program in our new distributed generation rulemaking, to ensure that our efficiency standards are continuously improved.

9. It is reasonable to permit eligible customer generation under Public Utilities Code Section 353.2 not to pay DWR ongoing power charges, and HPC, up to a MW cap as established in this decision.

10. It is reasonable and consistent with AB 1X and AB 117 to adopt an exception so that all customer generation installed after February 1, 2001, up to a maximum MW cap, are not required to pay DWR ongoing power costs.

11. It is reasonable to set an absolute cap of 3,000 MW for customer generation involving DWR ongoing power charges in order to minimize risk of cost-shifting to bundled customers. It is also reasonable to reevaluate this cap within three years of the date of this decision, or when the amount of installed customer generation reaches 1000 MW, whichever occurs first.

12. It is reasonable to limit the amount of non-renewable customer generation over 1 MW in size to half of the total cap, or 1,500 MW, in order to ensure that renewable generation has an advantage. It is also reasonable to apply this cap three increments: 600 MW by the end of 2004, an additional 500 MW by July 1, 2008, and the final 400 MW thereafter.

13. It is reasonable to provide a set-aside from the caps for UC / CSU as follows: 10 MW before the end of 2004, an additional 80 MW by the end of 2008, and an additional 75 MW thereafter.

14. If a Customer Generation unit serving new or incremental load can pass the physical test adopted in D.98-12-067, showing that the load is being met through a direct transaction does not otherwise require the use of transmission or distribution facilities owned by the utility, that load will not be considered as departing, and will not be obligated to pay a CRS in accordance with Public Utilities Code Section 369.

15. In the passage of AB 2228, the Legislature specifically considered and elected to make an exception for biodigester projects from any net metering or other charges for departing the utility system. Accordingly such biodigester projects are not required to pay CRS.

16. The CEC is the logical entity to determine eligibility for qualifying for the exceptions to paying the CRS as specified in this order, with additional assistance from and information provided by the utilities.

17. It is reasonable to count systems under 1 MW toward the cap on exceptions, but to automatically grant the exceptions authorized in this order.

18. This decision construes, applies, implements, and interprets the provisions of AB 1X (Chapter 4 of the Statutes of 2001-02 First Extraordinary Session). Therefore, Public Utilities Code Section 1731(c) (applications for rehearing are due within 10 days after the date of issuance of the order or decision) and Public Utilities Code Section 1768 (procedures applicable to judicial review) are applicable.

O R D E R

IT IS ORDERED that:

1. This order shall apply to the service territories of Southern California Edison (SCE), Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E).

2. The Settlement Agreement is rejected as inconsistent with Legislative and Commission policy and not in the public interest.

3. A mechanism for the determination of a Cost Responsibility Surcharge (CRS) applicable to Departing Load served by Customer Generation is hereby adopted, as set forth below.

4. Departing load that began to receive service from customer generation on or before February 1, 2001 except during any period and to the extent that the departing load thereafter receives bundled or direct access service, shall be exempt from all DWR bond charges and ongoing power charges.

5. Customer generation, not otherwise included in Ordering Paragraph 4, that commenced commercial operation on or before January 1, 2002, or for which (a) an application for authority to construct was submitted to the lead agency under CEQA, not later than August 29, 2001, and (b) commercial operation commences not later than January 1, 2003 are not required to pay DWR ongoing power charges.

6. Biogas digester customer generation eligible under AB 2228 are not required to pay any CRS charges.

7. Customer generation departing load that is under 1 MW in size and eligible for net metering pay DWR charges based on their net energy consumption and are not required to pay any of the other CRS components adopted in this decision. Customer generation departing load that is under 1 MW in size and eligible for financial incentives from the CPUC's self-generation program or from the CEC, are not required to pay any CRS, including the DWR bond charge, DWR ongoing power charges, any SCE or potential other utility historic procurement charges (HPC), and the "tail" competition transition charge (CTC).

8. Customer generation departing load that is over 1 MW in size but that otherwise meets all criteria in Public Utilities Code Section 353.2 as "ultra-clean and low-emissions", shall pay the DWR bond charge and tail CTC (if not otherwise excepted by Public Utilities Code Section 372 and / or 374), but are not required to pay DWR ongoing power charges or any HPC, except as provided in Ordering Paragraph 10 below.

9. Customer generation departing load other than that defined in Ordering Paragraphs 4-8 above are not required to pay DWR ongoing power charges, except as provided in Ordering Paragraph 10 below.

10. Exceptions adopted in today's decision as provided in Ordering Paragraphs 8 and 9, shall expire when the cumulative total of customer generation departing load eligible under those Ordering Paragraphs exceeds 3,000 MW, as determined on a first-come, first-served basis by the California Energy Commission. The amount of customer generation exceptions defined in Ordering Paragraph 9 shall be limited to 1,500 MW with no more than 600 MW by the end of 2004, an additional 500 MW by July 1, 2008, and a final 400 MW thereafter.

11. UC / CSU shall be granted a set-aside within the caps discussed in Ordering Paragraph 10 as follows: 10 MW by the end of 2004, an additional 80 MW by the end of 2008, and an additional 75 MW thereafter.

12. The MW caps, as defined in Ordering Paragraph 10, shall be reevaluated by this Commission within three years of the date of this decision, or when the amount of installed customer generation in Ordering Paragraphs 7, 8, and 9 reaches 1000 MW, whichever occurs first. At that time, we will also reevaluate the 1 MW size limit defined in Ordering Paragraph 7, to take into account developments in technology and economies of scale.

13. To the extent that Departing Load customers are responsible for paying a DWR ongoing power charge after reaching the MW cap described in Ordering Paragraph 10, such charge shall be set equal to the corresponding cents per kilowatt-hour (kWh) surcharge component in effect on the date of departure as determined pursuant to the Direct Access (DA) phase of R.02-01-011 and related or successor proceedings.

14. SCE is authorized to recover HPC from departing load not otherwise excepted in this order, and calculated as defined in the text of this order.

15. "Tail" CTC will be defined and calculated consistent with the text of this order. Departing load exempt from CTC pursuant to any statute, including without limitation Public Utilities Code Sections 372 and 374, as the legislation existed as of the adoption of this order, as well as additional exceptions adopted in this order, shall not be required to pay "tail" CTC.

16. The recovery of the CRS element relating to recovery of DWR bond charges shall be implemented once this decision becomes final and unappealable. During the interim, the bond charge component shall be tracked through the subaccount process established in D.02-10-063 and D.02-11-074.

17. PG&E, SCE, and SDG&E, respectively, are hereby directed to file necessary tariff revisions to incorporate and implement the other surcharge elements adopted in this order. The utilities shall make compliance advice letter filings within ten days of the effectiveness of this order, to implement the CRS element, other than bond charges, as adopted in this order. The advice letters shall be effective on filing, subject to post-filing review by the Energy Division.

18. The utilities shall report to the Energy Division and the CEC, on a quarterly basis, the amount of customer generation installed under the provisions of this order.

This order is effective today.

Dated April 3, 2003, at San Francisco, California.

MICHAEL R. PEEVEY
President

GEOFFREY F. BROWN
SUSAN P. KENNEDY
Commissioners

I will file a dissent.

LORETTA M. LYNCH
Commissioner

I will file a dissent.

CARL W. WOOD
Commissioner