COM/CXW/mzr **ALTERNATE DRAFT** Agenda ID #1151
(Alt. To Agenda ID #1147)

Decision **ALTERNATE DRAFT DECISION OF COMMISSIONER WOOD**
(Mailed 9/24/2002)

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

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I. Introduction

Today's decision addresses the issue of Direct Access (DA) customers' cost responsibility and related issues that arise as a result of the suspension of DA as ordered in Decision (D.) 02-03-055.[1] This decision establishes mechanisms to implement surcharges applicable to DA customers 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). The surcharges adopted in today's order are required to hold DA customers responsible for their share of costs as explained herein, and to prevent such costs from being unlawfully and unfairly shifted to "bundled" utility customers.

Although in D.02-03-055, we permitted DA customer contracts entered into on or before September 20, 2001, to remain in effect, we did so on the condition that bundled ratepayers would not be adversely impacted in terms of cost impacts. Specifically, we required that there be no shifting of costs caused by customers migrating from bundled to DA load.[2]

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[1] The issues of "Departing Load" cost responsibility and issues relating to the "switching exemption" are deferred to further proceeding and to a separate order. This decision does not discuss the "Rule 4: Switching Issue" - Subject to limited rehearing granted in D.02-04-067.

[2] DA customers purchase electricity from an independent electric service provider (ESP), and receive only distribution and transmission service from the utility. "Bundled" customers, however, rely on the utility for all these services. Distribution and transmission charges are "bundled" with a charge for the procurement of energy supplies.

These costs are comprised of: (1) costs incurred by the California Department of Water Resources (DWR) on behalf of customers in the service territories of the three major utilities and (2) costs incurred by each of the utilities through their own resources and contracts.

In pleadings and testimony of parties in this proceeding, a variety of terms have been used to refer to the charges to be imposed on DA customers pursuant to D.02-03-055. These terms have included expressions such as "non-bypassable charge," forward or ongoing costs, and "exit fee." For the sake of uniformity and clarity, we shall use the term DA "cost responsibility surcharge" (DA CRS) as an umbrella term taking into account all of the various charge components at issue in this proceeding that are necessary to hold DA customers responsible for the appropriate charges as adopted in this order.

In this order, we adopt the necessary measures and processes, in conjunction with companion proceedings in Application (A.) 00-11-038 et al. to implement DA Cost Responsibility Surcharges (CRS) for DWR historic costs incurred during 2001-2002, for 2003 prospective costs, and also a process for periodic updating in subsequent years. The CRS shall be determined on a total portfolio basis, taking into account both DWR and utility-procured resources, and shall reflect DA customers' respective share of costs associated with those resources. The DA CRS shall be composed of the following elements:

(1) DWR Bond Charge. The actual amount of this charge for DA customers shall be computed and implemented through a separate decision in the Bond Charge Phase of A.00-11-038 et al.

(2) DWR power charge covering DA customers' share of procurement costs between September 21, 2001 and December 31, 2002, representing DA customers' share of the

uneconomic portion of DWR costs incurred after DA suspension but prior to the implementation date for the instant order.[3]

(3) DWR power charge applicable to prospective costs for calendar year 2003, representing DA customers' share of the uneconomic portion of prospective DWR costs. The principles and criteria underlying the determination of DA cost responsibility for this component shall be determined as prescribed in this order.

(4) A separate charge to cover the ongoing above-market portion of utility-related generation costs, as we explain in further detail below.

The DA CRS components shall be applicable to DA customers on the following basis. The DWR Bond Charge shall be applicable to all DA customers except for those that have been continuously subscribed to DA both before and since DWR began its power purchase program. The DWR Power Charge shall be applicable to all incremental DA load that switched to DA between July 1 and September 20, 2001. Other DA customers that were on DA prior to July 1, 2001 shall be excluded from the DWR Power Charge. All DA customers, irrespective of the date they began to take DA service shall be required to pay the URG-related component of the DA CRS.

For purposes of billing, collection, and remittance of revenues to DWR, each of the utilities shall use the same procedures for DA customers as are currently used for bundled customers. We do not adopt an overall DA surcharge

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[3] The actual final amount of the DWR power charges shall be based on the specific forecast variables underlying the 2003 DWR revenue requirement that will be implemented in A.00-11-038 proceedings.

cap at this time. Instead, we defer consideration of a DA CRS cap at the first annual update after a more complete record can be established.

II. Background

This decision involves the determination of cost responsibility for DA load pursuant to the directives in D.02-03-055 in which we suspended DA effective September 20, 2001. We suspended DA pursuant to legislative directive, as set forth in Assembly Bill No. 1 from the First Extraordinary Session (AB 1X Stats. 2002, 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 and unforeseen 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 of the California utilities. As part of its provisions to deal with California's energy crisis, AB 1X also called for the suspension of DA, as set forth in Section 80110 to the Water Code:

> "After the passage or such period of time after the effective date of this section as shall be determined by the commission, the right of retail end use customers pursuant to Article 6 … to acquire service from other providers shall be suspended until [DWR] no longer supplies power hereunder."

In compliance with the mandate to suspend DA, we initiated proceedings in A.98-07-003. A proposed Administrative Law Judge (ALJ) decision was issued in that proceeding in June 2001, proposing a DA suspension date of July 1, 2001.

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

The Commission ultimately issued D.01-09-060, suspending the right to acquire DA after September 20, 2001. In D.01-09-060, we placed parties on notice, however, "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, 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 20, 2001 should be applied to direct access.[5] On March 27, 2002, we issued D.02-03-055 in this proceeding, determining that the DA suspension date should remain as "after September 20, 2001," in the interests of providing for predictability and regulatory consistency on a going-forward basis. DA contracts executed prior to September 20, 2001, were not suspended, but were made subject to the restrictions imposed by D.02-03-055. We emphasized in D.02-03-055 that bundled service customers should not be burdened with the additional costs that would otherwise shift to them due to the significant migration of customers from bundled service to direct access between July 1, 2001 (the suspension date originally anticipated in the ALJ Proposed Decision) and September 20, 2002 (the suspension date adopted by the Commission).

We noted that, in lieu of an earlier suspension date, DA surcharges must be considered as a means of preventing cost shifting and the development of these surcharges must be timely. We later clarified that prevention of cost

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[5] The administrative record relating to these specific issues in 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).

shifting meant that "bundled service customers are indifferent."[6] Should timely implementation of such charges fail to occur, we stated in D.02-03-055 that the proceeding would be reopened to reconsider the suspension date for DA.

III. Procedural Summary

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. By ALJ ruling issued March 29, 2002 in A.00-11-038 et al., a schedule was adopted for evidentiary hearings on DA cost responsibility. On April 22, 2002, the Commission issued D.02-04-052, transferring the proceedings on DA and DL cost responsibility from A.00-11-038 et al. to R.02-01-011.

Parties filed opening briefs on April 22, 2002, and, reply briefs on May 6, 2002 on legal issues relating to the Commission's right to impose cost responsibility charges on DA and DL customers. Opening testimony was mailed on June 6, 2002 and reply testimony was mailed on June 20, 2002. Evidentiary hearings were held from July 11 through July 24, 2000, regarding the appropriate charges to be assessed on DA customers to avoid cost shifting. By ALJ bench ruling on the first day of hearings, the scope of the evidentiary hearings was bifurcated to provide for separate consideration of departing load—as opposed to DA—cost responsibility issues. Post-hearing opening briefs were filed on August 30, 2002, and reply briefs were filed on September 6, 2002.

Active parties represented a range of interests including the investor-owned utilities (IOUs), parties representing bundled customers (i.e., Office of

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

Ratepayer Advocates (ORA), The Utility Reform Network (TURN), and California Energy Commission (CEC), and parties representing DA customers, either through industry associations or as individual customers. DWR also participated by sponsoring computer modeling scenarios. The most active parties representing DA interests that sponsored testimony included the California Large Energy Consumers Association (CLECA), California Industrial Users (CIU), and California Manufacturers & Technology Association (CMTA). Several other DA parties presented testimony or filed briefs.[7]

IV. Scope of Costs Subject to CRS

In compliance with D.02-03-055, charges must be imposed on DA customers sufficient to ensure that bundled service customers do not bear higher costs due to the migration of a significant number of customers from bundled to DA service between July 1 and September 20, 2001. This migration of DA load reduced the bundled customer base over which costs could be spread. Unless DA customers pay their respective share of such costs, bundled customers would have to make up the shortfall through higher bills, thus, resulting in a cost shifting.

By ALJ ruling dated March 29, 2002, parties were put on notice that the Commission would address in this proceeding "the full range of costs" necessary

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[7] Other parties submitting testimony or filing briefs include the Alliance for Retail Energy Markets and the Western Power Trading Forum (AReM/WPTF); Callaway Golf Company; the California Farm Bureau Federation (CFBF); the California Independent Petroleum Association; California Retailers Association (CRA); the City of Corona, Del Taco, Inc., and Lowe's Home Improvement Warehouse; the Eastside Power Authority; the Irvine Company; 7-Eleven, Inc.; the Los Angeles Unified School District; SBC Services, Inc.; Strategic Energy, LLC; and the University of California and the California State University (UC/CSU).

to avoid such cost shifting from DA to bundled utility customers. The ALJ Ruling defined the scope for determining surcharges, stating: "In order to ensure that the Commission is able to consider a fully compensable surcharge, a record must be developed that takes into account all possible cost responsibilities including but not limited to DWR purchase costs . . . attention will be focused on how such cost responsibility can be formulated."[8] DWR purchases are the obligations of retail end-users within the service territories of the three electric utilities. (See Water Code § 80104.) In D.02-03-055, we noted that these purchases included those made by DWR on behalf of DA customers who returned to bundled service and also those bundled service customers who later entered into DA arrangements. In D.02-03-055, the Commission observed that: "There would be a significant magnitude of cost-shifting if DWR costs are borne solely by bundled service customers, and direct access customers are not required to pay a portion of these costs that were incurred by DWR on behalf of all retail end use customers in the service territories of the three utilities during a time when California was faced with an energy crisis."[9]

DWR costs may be divided into two broad categories for purposes of assessing DA cost responsibility: (1) "historic" costs incurred between January 17, 2002 and the issuance of this decision, and (2) prospective costs (i.e., the "uneconomic "costs that will continue to be incurred under long-term DWR contracts from January 1, 2003 going forward until contract termination projected to be 2011. "Historic" costs may further be subdivided into costs incurred

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[8] ALJ Ruling, p. 5, emphasis added.

[9] See D.02-03-055, Finding of Fact 3.

(1) between January 17, 2001 and the DA suspension date of September 20, 2001 and (2) between September 21, 2001 and December 31, 2002.

Among the other potential categories of additional costs noted in the ALJ ruling as being subject to DA CRS were purchased power costs from qualifying facilities (QFs) and costs related to the utilities' retained generation. In D.02-04-067, the Commission referenced the scope of additional non-DWR costs noted in the March 29, 2002 ALJ ruling, and expressly clarified D.02-03-055 to make clear that the CRS will take into account recovery of relevant non-DWR costs and that DA customers will be held responsible for such costs as required by AB 1X and other statutes (e.g., AB 1890). (See D.02-04-067, Ordering Paragraph (OP) 1e.) D.02-04-067 affirmed that nowhere in D.02-03-055 are DA customers relieved of their responsibility for AB 1890 transition costs, including those transition costs collected by SCE and PG&E during the rate freeze.

The determination of a DA CRS thus must take into account all relevant costs that would otherwise result in cost shifting from DA to bundled customers of customers of the three major IOUs. The scope of costs include those of DWR pursuant to AB1X and Utility Retained Generation (URG)-related costs. We also take into account relevant companion proceedings where the Commission either has already adjudicated and adopted charges for DA cost responsibility or is in the process of adopting such charges for DA.

V. Legal Authority for Imposing Cost Responsibility Surcharges

We conclude that requisite legal authority exists as a basis to authorize and implement the cost responsibility surcharges adopted in the instant order. Further, under Code Section 701, the Commission has broad authority to regulate public utilities and to "do all things…which are necessary and convenient in the exercise of such power and jurisdiction."[10] Moreover, the changes or rates imposed must be "just and reasonable" and must not be unfairly discriminatory. (See Public Utilities Code Sections 451 and 453.) Consistent with these statutory requirements prohibiting discriminatory ratemaking, bundled customers may not be arbitrarily charged for obligations which rightfully are the responsibility of DA customers.

A. DWR-Related Costs

Within the broad statutory authority outlined above, the Commission has specific authority to establish charges for the collection of costs incurred by DWR pursuant to AB 1X. We conclude that this authority applies not just to bundled customers, but also extends to charges imposed on DA customers to the extent that DWR purchased power on their behalf or for their benefit.

DWR began buying electricity on behalf of the 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. AB 1X provides for funds to DWR from revenues generated by applying charges to the electricity that it purchased on behalf of retail end-users. AB 1X requires that DWR include in its revenue requirement "…amounts necessary to pay for power purchased by it…" (Water Code Section 80134(a)(2).)

Water Code Section 80002.5 states that "[i]t is the intent of the Legislature that power acquired under this division shall be sold to all retail end use customers served by electrical corporations, …." Water Code Section 80104 explains that "the retail end use customers shall be deemed to have purchased

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[10] All statutory references are to the Public Utilities Code, unless otherwise noted.

that power from the department. Payment for any sale shall be a direct obligation of the retail end use customer to the department." Thus, consistent with the provisions of the Water Code, those DA customers that took bundled service prior to September 20, 2001 are responsible for paying a share of the DWR revenue requirements. The DWR costs for which DA customers bear responsibility include both previously incurred costs as well as an ongoing cost component. For previously incurred costs, DWR has not yet received full payment. The State of California is in the process of finalizing the sale of bonds to finance DWR's prior undercollections, and bond charges are being determined in A.00-11-038 et al. In Section IX, we address the legal and policy issues relating to DA customers' responsibility for paying a share of the bond costs.

B. Non-DWR Related Costs

Certain parties argue that the IOUs' ability to collect utility-related costs from DA customers expired under the provisions of AB 1890 effective after March 30, 2002, and that without specific legislation, the attempt to charge such costs violates the rule on retroactive ratemaking and Public Utilities Code Section 728. When customers entered into their DA agreements, the Commission had already established non-bypassable charges to be paid by DA customers, as authorized by AB 1890. These parties claim that AB1X does not give the Commission the authority to impose a new surcharge for non-DWR costs, and do not believe any other statute gives the Commission the authority to impose surcharges that are not in any way related to the delivery of electricity to DA customers.

We also conclude that legal authority exists for imposing charges on all DA customers for their share of the uneconomic utility-related costs. In this regard, Public Utilities Code Section 370 expressly states that DA customers are required to bear enumerated "transition" costs:

> The commission shall require, as a pre-requisite for any consumer in California to engage in direct transactions permitted in Section 365, that beginning with the commencement of these direct transactions, the consumer shall have an obligation to pay the costs provided in Sections 367, 368, 375, and 376, and subject to the conditions in Sections 371 to 374, inclusive, directly to the electrical corporation providing electricity service in the area in which the consumer is located.

Public Utilities Code Section 369 provides further 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 . . . ."

These “transition costs” were 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 provided for an “orderly” transition to a competitive generation market which would be completed by March 2002. (Public Utilities Code Section 330.)[11]

Public Utilities Code Section 368(a) established that electric rates would remain fixed at the June 10, 1996 levels, 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

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11 Except as otherwise indicated, all further statutory references are to the Public Utilities Code.

Competition Transition Charge (CTC), allowed the utilities to accrue the revenues to collect transition costs.

The Commission was further directed by § 367(e)(2) to ensure that bundled service customers "shall not experience rate increases as a result of the allocation of transition costs."

AB 1890 provided certain exceptions to the general rule that all CTC must either be recovered within the rate freeze period, or not collected. The Commission's second Post Transition Ratemaking (PTR) order (D.00-06-034) considered these exceptions. There, the Commission directed that, at the end of the rate freeze, all customers, bundled and DA, will pay a CTC charge that will be adjusted annually, to cover ongoing recoverable above-market QF power costs and some minor employee-related transition costs. According to the decision, both groups of customers will pay a CTC charge that will be trued up annually and that this charge will be based on a forecast of expected above-market costs.

When the Commission addressed this "Tail" CTC in D.00-06-034, it envisioned a largely unregulated generation market after the end of the rate freeze. Because utilities would be at risk in the market for recovery of their generation costs, it was important that they have assurance of recovery of these identified costs through an ongoing CTC charge.

After the extreme escalation in wholesale prices which began in Summer 2000, however, it became apparent that California's transition to electricity deregulation was not working. Beginning 2001, the Legislature responded by enacting emergency measures to deal with the energy crisis. Among these measures was Assembly Bill No. 6 from the First Extraordinary Legislative Session (AB 6X). AB 6X prohibited divestiture of any "facility for the generation of electricity owned by a public utility" prior to January 1, 2006 and stated that "[t]he Commission shall ensure that public utility generation assets remain dedicated to service for the benefit of California ratepayers." AB 6X also amended existing statues to delete any reference to the market valuation of the utilities' generation assets, which had been an essential step in the calculation of the utilities' uneconomic costs. (Public Utilities Code Section 367 (b).)

Certain parties argue that in view of AB 6X, there is no risk of non-recovery of generation costs and no need for ongoing CTC because such costs will be included in cost of service based rates. Yet, nothing in AB 6X rescinds the intent of the Commission that all customers, including DA, should pay a charge for the uneconomic cost of QF power. While the utilities' generation portfolio are likely to contain both above market and below market assets, they will collect the costs of the overall portfolio from their customers, as provided in this order.

The recovery of the uneconomic costs associated with QF and other purchased power contracts initiated before December 20, 1995 is allowed by AB 1890 (Section 370) through ongoing CTC. AB 1890 further directed the Commission to collect three distinct categories of costs from all customers after March 31, 2002. Under § 367(a)(2), the Commission must collect the following categories from all ratepayers: (1) "employee-related transition costs" through December 31, 2006, (2) "power purchase contract obligations" for the duration of the contracts, and (3) above-market Incremental Cost Incentive Prices (ICIP) associated with SCE's San Onofre nuclear generating plant through

December 31, 2003.[12] Electric restructuring implementation costs are also allowed to be recovered after the rate freeze.[13]

The Commission is giving further consideration to the end of the rate freeze, along with the extent and disposition of transition (stranded) costs left unrecovered. (D.02-01-011, mimeo., page 25.) Moreover, pursuant to §§ 451, 728, and 761, the Commission is also giving further consideration to what rate levels are necessary to assure utilities are reasonably creditworthy and financially healthy, in order for utilities to fulfill their responsibility to procure and deliver reliable, safe and adequate electricity. The result may or may not require a continuation of rates at frozen rate levels. We recognize that the timing of the end of the rate freeze, the corresponding impact on transition cost recovery, and the definition of what were formerly considered stranded costs are issues that are being considered in A.00-11-038 et al., in the rehearing of D.01-03-082, as ordered by D.02-01-001. We are also considering in that proceeding the impact of AB 6X and AB 1X on the various provisions of AB 1890. Here, we find that ongoing CTC should be included in DA CRS. This determination is subject to adjustment, depending on our findings in A.00-11-038 et al. We will not prejudge this now.

In SCE's case, Resolution E-3765 has already extended the rate freeze to collect the 2000-2001 wholesale purchased power undercollection. The Commission has proposed a similar remediation in the U.S. Bankruptcy Court for PG&E, and if adopted by the court, would satisfy this part of AB 1890 for

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[12] Cal. Pub. Util. Code § 367(a)(1), (a)(2), (a)(4).

[13] Section 376.

PG&E. Since SDG&E ended its rate freeze before December 31, 2001, this provision of AB 1890 would not apply to it.

Another category of costs included in the scope of costs subject to CRS is the past wholesale undercollection from the 2000-2001 energy crisis incurred by the utilities before DWR began procuring electricity on the behalf of utility customers. The responsibility for direct access customers to pay for SCE's undercollection reflected in its Procurement Related Obligations Account (PROACT) has been addressed in A.98-07-003. We issued D.02-07-032 in that proceeding, establishing a Historical Procurement Charge (HPC) of 2.7 ¢/kWh for all DA customers, to remain in effect until a CRS is established in this proceeding. The HPC is intended to allow the PROACT balance to be recovered from DA customers to the extent they are responsible for those costs that will be incurred. Effective with the implementation of a CRS in this proceeding, D.02-07-032 orders that the HPC charge shall drop to 1.0 ¢/kWh until the undercollection of $391 million is recovered.[14]

VI. Standard for Determining Ratepayer Indifference

A. Parties' Positions

Although the Commission provided a broad standard in D.02-03-055 for bundled ratepayer indifference relating to DA suspension, the specific methodologies to implement that standard were left for this proceeding. Parties disagree in a number of respects concerning the manner in which indifference

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[14] Several parties have filed applications for rehearing of D.02-07-032, and the matter is pending before the Commission. Today's decision in no way disposes of or prejudices any issues raised in these rehearing applications.

costs should be computed and assigned among DA customers. Parties' disagree on various issues, including whether indifference should be determined only with reference to DWR costs, or whether it should incorporate the entire procurement portfolio, including both DWR and utility-related costs. Among those who agree that utility-related costs should also be considered, there is disagreement as to whether the calculation should incorporate all URG costs, including below-market resources, or be limited to those specific categories of so-called above-market transition costs authorized for recovery under Public Utilities Code Section 367. There is also disagreement as to how the above-market component should be calculated, and what form of market proxy should be used.

There is also disagreement in how the cost-shifting effects of customer migration from bundled to DA load should be captured and measured. Most parties rely on a computer-simulation modeling approach to compute the net difference in DWR procurement-related costs on a before-and-after-DA-suspension basis. The simulations thus compare the cost difference between: assumed bundled load that (1) includes the incremental load that migrated to DA between July 1 and September 20, 2001, and (2) excludes that incremental DA from bundled load. The difference represents the cost-shifting effects of the DA migration.

DWR's approach calculates the change in the unit cost of the total net short (i.e., the DA load served via DWR's long-term contracts and DWR's spot purchases) between alternate suspension dates of July 1 DA load of 2% and

September 20, 2001 DA load of 13.62%.[15] DWR thus defines "indifference" to mean that the rates paid by bundled customers should not increase as a result of suspending DA as of September 20, 2001 rather than July 1, 2001. The difference in costs between these two DA load levels represents the increase in the average cost of net short power to bundled customers due to the migration of customers from bundled to DA load between July 1 and September 20, 2002. The cost differential represents the portion of the DWR revenue requirement incremental DA customers would need to pay to avoid cost shifting to bundled customers. In modeling indifference costs, DWR focused on only its own costs and ignored utility-related costs.

CLECA, CMTA, SCE, and TURN (among others) agree with DWR's general approach of comparing costs based on the change in incremental DA load between these two dates, but disagree with focusing only on DWR power. CLECA's approach defines indifference in reference to the change in unit cost of the total bundled service portfolio (i.e., DWR's long-term contracts, DWR's spot purchases, and the IOUs' URG) between the two suspension dates.[16] CLECA et al. point out that the DWR power represents only a fraction of the power sources

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15 DWR/McMahon, Ex. 4; DWR/McDonald, Ex. 8.

16 CLECA/Barkovich/Yap, Ex. 28, p. 36. Strategic Energy proposed a method similar to CMTA, except that it involves liquidating a portion of DWR's contracts by the amount of increased DA load and assigning the contract cost above the revenue derived from the liquidation to DA customers. (Strategic Energy/Lacey, Ex. 37, p. 5) We find no evidence, however, that DWR is willing to liquidate a portion of its contracts. (Strategic Energy/Lacey, Tr. 6/767.) Even if DWR was willing to liquidate a portion of the contracts, there is no evidence that the exact portion associated with the increase DA level could be liquidated and liquidated in a manner equitable for each of the IOU service territories.

serving bundled customers. DWR's method thus assigns zero uneconomic DWR costs to the portion of bundled customers' load served with URG resources.

The majority of power used to serve bundled customers comes from URG sources. The DWR power share of total resources varies by utility and changes over time. In all cases, the DWR share of total power requirements in any given year will reflect the amount of utility nuclear generation (which varies when there is refueling), weather, and hydro availability, for PG&E and to a lesser extent SCE. Furthermore, the share will be influenced by load growth and the percentage of DA load. Under the DWR/Navigant approach, the cost of the bundled portfolio actually declines under a September 20 suspension date, once the DA cost responsibilities are included.[17] CLECA proposes as an alternative that the Commission does not focus on DWR costs alone but rather on the entire bundled energy portfolio costs.

The total cost of generation used to serve bundled customers is the combined weighted average cost of both URG and the DWR power. DWR power has been, on average, more expensive than the weighted average cost of URG power, to date. DWR's own analysis shows its average power prices to finally drop to $69 to $70/MWh after several years. PG&E's URG cost under the recent URG decision is about $52/MWh. SCE's is about $52/MWh, and SDG&E's is about $57/MWh.

If DA customers leave bundled service, their share of URG power is thus made available to serve remaining bundled load. DA customers will not receive DWR power either, and any excess DWR power from non-dispatchable

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[17] *Id.*, p. 25.

sources can be sold in the market. Fixed costs, however, will still have to be covered. The departure of the DA load will leave more of the lower cost URG power available to serve bundled customers and help offset the impact of DWR power costs.

The CLECA approach mixes DWR and URG unit costs into a single blended rate, and does not segregate a rate just representing URG-related costs. Both SCE and SDG&E argue that the CLECA methodology needs to be refined to provide for a separate URG rate because under their proposals, all DA customers will pay a CTC rate, but not necessarily a DWR rate. SCE and SDG&E have differing proposals as to how the indifference calculation should be made, but both agree on the overall approach which incorporates a separate calculation of above-market URG costs based on a market proxy. SDG&E defines indifference as (1) payment by migrated DA customers of their share of post-migration above-market DWR long-term contracts costs, and (2) payment by DA customers of their share of AB1890 above-market URG costs.[18]

CMTA proposes an alternative approach to that of DWR and CLECA. CMTA defines indifference as there being no change in the amount of above-market DWR costs paid by bundled service customers between the two suspension dates and allocating above-market URG costs to both DA and bundled service customers.[19] Under CMTA's alternative approach, there is no specific comparison of the cost difference between DA loads at discrete points in time. DA and bundled service customers would each be allocated an equal cents

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[18] SDG&E / Trace, Ex. 54, pp. 5 – 7; SDG&E / Nelson, Ex. 57, pp. 1 – 4.

[19] CMTA / Beach, Ex. 39, p. 10 – 19.

per kWh charge for the recovery of uneconomic DWR costs.[20] By contrast, CMTA claims that Navigant's method results in incremental DA loads bearing 39% of uneconomic DWR costs in 2002, even though they represent only 11.6% of total loads.[21] CMTA argues that Navigant's approach thus does not result in ratepayer indifference, but actually leaves bundled ratepayers with lower rates.

Under CMTA's approach the uneconomic costs of the DWR portfolio would be determined by comparing per-unit costs of the DWR contracts against a market benchmark price based on the all-in costs of a new gas-fired combined-cycle power plant. CMTA notes that this is the same benchmark that the Commission used in its FERC complaint concerning DWR contracts. This market proxy includes both variable and fixed capital costs.

B. Discussion

We conclude that the comparison of the difference in costs between incremental DA load in and out between July 1 and September 20, 2001 more closely conforms to the intent of D.02-03-055 than does the CMTA method. Specifically, the key elements of our adopted methodology shall be based on the alternate DA suspension dates, consistent with the objective of D.02-03-055 that we adopt surcharges in lieu of an earlier suspension date. Thus, the adopted surcharges computed on this basis shall ensure bundled service customers are indifferent to costs under the two suspension dates of July 1 or September 20, 2001.

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[20] CMTA, p. 4.

[21] CMTA's supporting calculation of the relative allocation of uneconomic costs using the Navigant method is set forth in Table 5 of CMTA Exhibit 39.

We conclude that the CMTA approach does not satisfy the Commission requirement that bundled service customers be indifferent between two discrete suspension dates. CMTA's method provides no connection between the alternate suspension dates that can be tied to bundled service customer indifference with respect to costs. CMTA's proposal also incorporates the use of a market proxy to measure uneconomic costs. We address the issue of market proxies in Section XIV.

We also find that the proper approach to computing ratepayer indifference must take into account the total portfolio of energy sources, not just those provided by DWR. ORA objects to CLECA's indifference approach, arguing that the cost of URG resources are "off limits" to DA customers, but are dedicated to service of bundled customers. ORA argues that it blurs the distinction between DA and bundled service to assign an offsetting savings to DA customers.

The intent underlying the indifference calculation, however, is to determine the cost shifting that resulted from the migration of certain bundled customers to DA. An accurate measure of cost shifting cannot be determined if we selectively focus only on certain components of cost shifting while ignoring others. The directive in D.02-03-055 was to consider all cost shifting, not just those effects attributed to the DWR portion of the total portfolio. The netting of URG savings does not imply that those URG resources are somehow dedicated to serving DA customers. The attribution of savings to DA customers merely reflect the change in costs experienced by bundled customers associated with their use of those dedicated resources.

The total portfolio approach to computing bundled ratepayer indifference, as adopted herein, will require the computation of two rate components, one relating to remittances to DWR and the other relating to payment to the utility for utility-related uneconomic costs.

The calculation of indifference costs on a total-portfolio basis still incorporates the use of the DWR modeling of costs on a DA in/out basis. The DWR model already incorporates variables for both DWR and URG resources to determine resources to be dispatched. Although DWR's model scenarios only focused on the costs associated with its long-term contracts and spot-market purchases, both the DWR and the URG costs for the pre- and post-DA migration scenarios are available from the DWR-supplied spreadsheets. This DWR modeling information can thus be used to compute an indifference cost on a total portfolio basis. Once the total indifference cost level is determined, the DWR portion of that indifference cost can be identified by calculating the above-market cost and related kWh of the IOUs' own resources and subtracting that from the total portfolio indifference cost. The CLECA total portfolio methodology mixes URG and DWR revenue requirements. Therefore, a separate benchmark must be determined to identify the stand-alone, uneconomic portion of URG. This stand-alone component is needed because those continuous DA customers who will not pay DWR-related CRS, will still be responsible for utility-related CRS.

PG&E points out that the split between URG and DWR components of CRS does not affect the aggregate division of costs *between* bundled and DA; it *will* affect the allocation *among* classes of bundled customers. The effect is due to the fact that the ongoing URG and DWR charge are established using different cost allocations. Thus, the larger the ongoing URG component, the more the allocation of the DA total portfolio indifference amount is weighted toward top 100 hours, and the less toward equal cents per kWh allocation.

Accordingly, we shall adopt a DA CRS component representing the above-market portion of the URG portfolio for each utility. To the extent the utility operates its URG portfolio to meet bundled service load, its variable costs of operation will be at or below the alternative costs of procuring energy in the market. Nevertheless, the economics of fixed and variable costs within the portfolio will vary yearly depending on market conditions. For example, baseload generation may be more costly than market purchases during off-peak hours, but less costly than market purchases during on-peak hours.

The above-market portion should consist of the difference between the cost (revenue requirement) of the URG portfolio and an estimate of its value in the market.[22] This CRS component shall be calculated using the same "stranded cost" approach the Commission previously adopted for the calculation of the CTC. This will ensure that DA customers will be responsible for the same proportional share of "stranded costs" as bundled service customers will bear. This charge shall then be deducted from the indifference cost calculation to determine the amount that should be remitted to DWR. We consider the issue of a market benchmark at Section XIV.

VII. Modeling of DA Cost Responsibility Surcharges for DWR Costs

A. Role of Modeling in Analyzing DA Cost Shifting

As a framework for analyzing DA cost shifting effects, computer modeling simulations were offered into evidence. An initial series of model

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[22] SCE also proposes to include the Independent System Operator (ISO) costs associated with the operation of this portfolio in this cost responsibility.

simulations was performed by DWR through its independent consultant, Navigant, using the PROSYM model. The Commission's Energy Division conducted a technical workshop on April 12, 2002 in which parties agreed upon various modeling scenarios to be performed by DWR. DWR submitted original modeling runs to parties on March 8, 2002, and revised on March 19, 2002, incorporating a base case with 10 scenarios and two sensitivity cases.

DWR's modeling analysis sought to compute DA cost responsibility charges at the level necessary to keep bundled customers' retail rates from increasing to cover any added cost burden caused by customers switching from bundled to DA service between July 1 and September 20, 2001. DWR thus calculates the cost shifting that results from the increase in DA participation between these dates. DWR computed a levelized fixed charge covering the period from inception of DWR purchases in January 2001 and extending over the next 15 to 20 years, to capture the net change in DWR power costs over the life of its long-term power contracts. The costs for electric purchases for the period from January 17, 2001 through September 2001 were higher than the revenues that the DWR collected from the IOUs. In its calculations, DWR assumed that a pro-rata share of the shortfall for this period is covered by DA customers.

A number of parties criticize the Navigant modeling approach. On a policy level, some parties question the merits of relying on long-term modeling at all to determine DA cost responsibility, arguing that any attempts to litigate long-term models will be fraught with controversy, speculative, and an unproductive use of time and resources. Other parties support the use of models to perform long-term forecasts, in general, but take issue with Navigant's modeling, in particular. These parties claim that the Navigant analysis systematically overstates DA customer responsibility for DWR procurement costs. The problems cited are both conceptual (e.g., the focus solely of DWR portfolio costs) and factual (e.g., levels of DA load, market prices, and assumptions regarding sales below prevailing spot prices.)

PG&E, SCE, SDG&E, and ORA all base their CRS calculations on Navigant Scenario 8. Certain parties representing DA interests, however, propose that instead of the Navigant model, the Commission rely on an alternative model sponsored by Henwood Energy Services, Inc. (Henwood) as the basis for forecasting DA CRS. The Henwood Model was offered into evidence through the testimony of J. Richard Lauckhart, Director of Henwood (Exh. 31). Henwood presented modeling results on behalf of a consortium of parties, performing a quantitative analysis of the impact of the increase in DA customers on DWR costs and to review Navigant's work.

Henwood modeled a "base case" that represented a revision of Navigant's original base case, updated to reflect Henwood's assumptions. Henwood estimates that the indifference costs associated with DWR power over the years 2002 through 2011 would be $1.96 billion higher than determined under the Navigant modeling, resulting in a lower DA CRS.[23]

We address the merits of the differences between the Navigant and Henwood modeling in Section XIII below. The different DWR cost values under the models are summarized below:

[23] See Exh. 31, Attachment A, Table 11, page 18 for comparison of cost differences between Navigant and Henwood modeling.

B. Summary of Proposed CRS Based on Modeled Results

An overall summary of parties' proposed DA CRS cost elements is set forth in Appendix A. We summarize parties' proposals below, regarding DWR costs. Proposals for the URG component are discussed in Section XIV.B.

PG&E

PG&E's proposal for calculating DWR-related CRS is based on the Navigant approach Scenario 8, which results in a DWR charge of 3.277 ¢/kWh for 2003, declining to 1.878 ¢/kWh by 2007.[24] PG&E proposes that the Commission direct DWR to present final calculations consistent with its proposed revenue requirement in the DWR revenue requirement proceeding, and that the DWR DA CRS be adopted annually in that proceeding.

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24 PG&E Exh. 41, Table 3-1

SCE

SCE is also generally supportive of the Navigant Scenario 8 modeling approach. SCE indicates that using the Navigant approach, it would require a DA CRS of 2.6 ¢/kWh to recover the applicable share of the 2003 DWR revenue requirement.

SDG&E

SDG&E proposes that its CRS be set based on an initial 15-year statewide levelized annual cost of 1.22 ¢/kWh, subject to correction of DA load figures as specified in its testimony.[25] Based upon Navigant Model Scenario 8, SDG&E's utility-specific 15-year levelized CRS would be 2.76 ¢/kWh. Full recovery of the DA CRS for SDG&E's share of the 2003 DWR revenue requirement would be 4.48 ¢/kWh.[26] SDG&E's CRS is higher than the other utilities because SDG&E has a higher percentage of load served by DWR without a proportionately higher DA load over which to spread the costs.

ORA

ORA's 2003 DWR CRS charges for forward DWR costs is $42.52/MWh, and its proposed historical DWR charge is $11.95/MWh.

CLECA

CLECA proposes that the DWR costs be levelized over a period of 10-15 years. Applying its total portfolio approach under the Henwood Base Case, CLECA calculates a CRS of $21.69/MWh for 2002 declining to $7.02/MWh by 2011. Appendix C shows CLECA's calculation of actual annual forward costs

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[25] See Section 6 of Trace Testimony; Exh. 54

[26] See Exh. 55/Trace, p. 6

for the period fourth quarter 2001 through 2011 based on two Henwood model scenarios. In each scenario, the total portfolio CRS-related costs drop significantly over the 10-year period. The CRS in the earlier years under the total portfolio method are lower than the DWR-only fees, reflecting the effect of the lower-cost URG power on the bundled portfolios.

CLECA calculates levelized forward DA CRS using a 15-year recovery period, both with an initial implementation at the start of the fourth quarter of 2002 and with a two-year delay under which utility undercollections would be collected from DA customers first. The 15-year levelized charges with a two-year delay and associated financing costs, fall at or below $14.25/MWh. Without the two-year delay, the Henwood scenarios would fall at or below $13.52/MWh.

CLECA also presents calculations of its proposed 15-year levelized cost on a utility-specific basis. Under the Henwood Base Case on Table 1, the statewide 15-year levelized cost, with a two-year delay, is $14.25/MWh. The comparable figure on Table 2 for PG&E is only $7.51/MWh, while the figures for Edison and SDG&E are $19.17/MWh and $29.08/MWh respectively. Comparable figures for the three utilities using the Henwood Base Case with higher Market Prices are $5.11/MWh, $15.93/MWh and $25.48/MWh.

The levelized forward costs for PG&E under the Henwood Base Case Scenario are $7.51/MWh over 15 years with a two-year deferral in recovery, or $7.12/MWh with no deferral. These figures exclude any bond charge. In order to mitigate the effects of higher charges applicable to SDG&E, CLECA recommends a 20-year recovery period.

CIU

CIU proposes the application of a 20-year levelized charge on a statewide uniform basis. Thus, CIU does not calculate separate utility-specific charges. CIU calculates a levelized annual charge of 1.552 ¢/kWh over a 20-year period covering both an historical and an ongoing DWR component. CIU calculates non-levelized ongoing charges starting in 2002 of 1.69 ¢/kWh declining to 0.19 ¢/kWh by 2011, and terminating thereafter. CIU relies on Henwood's modeling assumptions. CIU assumes that power will be sold off system at 100% of the PROSYM forecasted spot price. (See Chalfant (CIU) Exh. 33, pp. 7-8.)

CMTA

CMTA proposes the use of a 20-year levelized charge that takes into account the total utility portfolio. CMTA's forecasts of the levelized charge for the ongoing portion of costs is 0.407 ¢/kWh, covering the DWR contract costs for the 2002-2011 period. CMTA adds a component of 0.285 ¢/kWh to amortize the previously incurred DWR costs during the historic period through the fourth quarter of 2001. This calculation is set forth on Table 3 of Exh. 39, Testimony of Beach, as reproduced in Appendix D of this order.

C. Merits of Multi-Year Modeling Versus Annual Forecasting

1. Parties' Positions

A number of parties call into question the whole rationale for modeling multi-year forecasts as a basis for DA CRS. Whether the modeling is performed by Navigant, Henwood, or another entity, the reliability of long-term forecasts remains in question. Parties are in dispute over whether the Commission should rely at all on multi-year modeling forecasts of DWR costs or should simply perform one-year-ahead forecasts of costs subject to annual true ups.

The modeling efforts performed in this proceeding by DWR/Navigant and Henwood involved running complex models with multiple assumptions to forecast annual revenue requirements through 2011. In order to develop revenue requirements over such a long-time horizon, DWR and Henwood necessarily assembled long-term cost forecasts of total load and net short load on a statewide basis, new capacity additions and gas prices, among other items. For the utility-specific analysis, additional assumptions regarding inter-utility contract allocation are required.

The advantage of performing multi-year forecasts of cost responsibility is that the effects of relatively high costs in the early years can be combined with declining costs in later years to yield a "levelized" annual charge. The levelized charge minimizes the burden on DA customers in the early years by deferring a portion of those costs into later years, with the deferred portion financed at an assumed cost of money.

Several parties express concern, however, regarding the uncertainty surrounding forecast assumptions, particularly as they extend farther into the future. Adopting a method of determining DA charges that requires a long-term forecast will serve to make for more contentious proceedings. A levelized charge methodology results in charges for 2003 being affected by the assumptions made about market conditions as far in the future as 2011. Although long-range forecasts are necessary to evaluate long term-term decisions such as the purchase or construction of capacity, various parties argue that such forecasts are not needed for assigning cost responsibility in this case. Rather than litigating long-term forecasts in this proceeding, these parties propose setting the DWR charge on an annual basis.

In addition to the uncertainty associated with developing a long-term forecast, levelizing costs may create inter-year cost shifts between bundled and DA customers. In DWR's scenarios, the cost per kilowatt-hour (kWh) increase to bundled customers attributable to DA tends to be highest in 2003, and declines through 2011.

TURN raises the concern that levelized fixed charges have the potential effect of forcing bundled service customers to lend DA customers money at an effective 7.1% interest rate with up to a 20-year term. Based on DWR's Revised Base Case, TURN computes that bundled service customers would pay $200 to $300 million extra annually over the 2002-2008 time frame (by as much as $300 million per year in 2002-2004). On a present-value basis, they could pay $1.5 billion more by the end of 2008 if a levelized direct access loan was adopted. The $1.5 billion in excess payments would then be repaid through 2021.

TURN argues that if direct access provides such a benefit to its recipients, it should at least stand on its own feet without subsidized low-interest financing from bundled service customers. If the Commission does implement a levelized charge, TURN believes that a balancing account should be established, ensuring that the financing costs used to benefit direct access customers remain within each customer class.

As an alternative to computing a levelization of future forecasts, various parties propose, instead, simply adopting an annual cap on the maximum amount to be paid by DA customers in any given year. Any excess over the cap would then be deferred into future years.

2. Discussion

We conclude that long-term models serve a useful role in this proceeding, but not for the purposes of setting a levelized annual charge. We decline to rely upon the multi-year modeling forecasts presented by any of the parties in this proceeding as a basis to set specific levelized annual charges applicable to DA customers. We agree that the assumptions made regarding key variables extended several years into the future are too uncertain to form a basis for setting specific levelized charges in this order. We still find that the multi-year forecasts are relevant, however, by providing more generalized indications of longer-term trends in the relative trend of DA CRS of uneconomic costs over time.

For purposes of setting the CRS effective for the year 2003, we need only to rely on a single year-ahead forecast. We further conclude that there should be consistency between the forecast assumptions underlying the DWR charges paid by bundled customers and by DA customers. Otherwise, the use of inconsistent forecast assumptions would result in either under- or over-recovery of the respective shares of DWR costs from bundled and DA customers, and our goal of bundled ratepayer indifference would be undermined. Since the DWR power charges applicable to bundled customers is being determined in A.00-11-038 et al., we shall require that the assumptions underlying the calculation of DA CRS be consistent with the 2003 DWR/Navigant modeling underlying the revenue requirement implemented in the A.00-11-038 et al. proceeding.

Various parties representing DA interests argue that the modeling work performed by Navigant is unreliable for use in this proceeding, and the modeling performed by Henwood is superior and should be the sole model relied upon for assessing costs and charges in this proceeding. CIU, in particular, notes the series of modeling mistakes and corrections made by Navigant through the course of this proceeding.[27] CLECA also claims that the Navigant scenarios suffer from major analytic flaws, including too high an estimate of new power plants, which depresses market clearing prices (MCP) for electricity, and too low an estimate of prices for off-system sales (50% of MCP).

DWR replies that the majority of parties' criticisms of its modeling focus on DWR's "base case" which was first submitted in March 2002, but completely ignore the updates reflected in DWR's Scenarios 1, 7, and 8, distributed to the parties in late April 2002. DWR argues that these updated scenarios responded to the majority of the criticisms raised by parties, and that most of parties' criticisms relate to the now outdated March 2002 version of the model.

We note that, despite their differences, there are a number of similarities between Navigant and Henwood's modeling efforts. Both used the same basic modeling tools: Henwood's "Electric Market Simulation System" and accompanying NERC database. Both also used Henwood's production simulation model, PROSYM. Navigant's starting point was Henwood's publicly released NERC database circa the fall of 2000, which it then modified. Henwood's analysis relied on its most recent NERC database released in the spring of 2002, which Henwood then modified. From that point, the two firms took separate approaches to performing the CRS modeling.[28] Given the common

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[27] See CIU Opening Brief, dated August 30, 2002, pages 14-18.

[28] See Exh. 31, Attachment 1, page 23.

elements between the modelers, we see no necessity to elevate one modeler over the other as having a favored position for future modeling assignments. The participation of Henwood in this proceeding contributed positively to the quality of the modeling and forecasting data in the record. Having multiple modelers offers a broader perspective and a forum for more critical evaluation of modeling conventions. We review the model's results and adopt a prescribed methodology for calculating the DA CRS components for ongoing costs in Section XIII.

D. Verification of Computer Models

By adopting a DA In/Out total portfolio approach, as described in more detail above, we are potentially creating a "Battle of the Models." In this case, that possibility is reduced by the fact that the major participants are using similar approaches. However, to avoid creating a black box decision-making procedure, where the Commission's substantive decisions are mechanical outputs of models, the Public Utilities Code requires that we observe the model validation requirements of Public Utilities Code section 1822, which provides:

> (a) Any computer model that is the basis for any testimony or exhibit in a hearing or proceeding before the commission shall be available to, and subject to verification by, the commission and parties to the hearing or proceedings to the extent necessary for cross-examination or rebuttal, subject to applicable rules of evidence,…"

Section 1821(e) defines "verify" to mean "…to assess the extent to which the computer model mimics reality."

The commission has interpreted this as validating a model by conducting backcasts in order to establish the extent to which the algorithms that make up the model are capable of replicating actual events. Prosym and the

Electric Market Simulation System, the models which underlie the analyses of both Navigant and Henwood, have not yet been validated in this way.

As the discussion above makes clear, the outcome of application of different data sets to this model can have significant consequences for developing costs that would borne by bundled service customers. If the commission is to continue to use the methodology described in this decision, it is appropriate for Prosym and the Electric market Simulation System to be verified by the Commission as required by the statute. The Energy Division should discuss with Henwood and Navigant how verification can be accomplished in time for the next decision in this docket.

VIII. Structure of Costs Comprising DA CRS

Although the Navigant and Henwood model differ with respect to various forecast assumptions and modeling conventions, they generally agree on the overall structure of the DA CRS. We shall, therefore, adopt the following elements for purposes of a DA CRS.

(1) Revenue shortfall for DWR costs incurred from January 17, 2001 up to September 20, 2001, the date that DA was suspended by Commission order. This shortfall has been financed on an interim basis with interim loans and General Fund advances, but will ultimately be covered by the sale of Bonds.[29]

(2) DWR costs incurred from September 2001 through December 31, 2002. Bundled customers are currently paying for these costs in DWR power charges. DA

[29] The DWR bond charge revenue requirement are being implemented in A.00-11-038 et al. DWR power charges for 2003 are currently being determined in A.00-11-038 et al.

customers are not currently paying for their share of these costs.

(3) Prospective DWR costs for calendar year 2003.

(4) DWR costs for future years through the duration of long-term contracts entered into by DWR.

(5) Ongoing uneconomic utility-related costs paid pursuant to AB 1890.

IX. "Historic Costs"

A. Parties' Positions

1. Separate Levelized Charge or Bond Charge

Current bundled customers, like current DA customers who were bundled service customers during portions of 2001, did not pay fully for the DWR's procurement costs during the historic period between January 17, 2001 and September 20, 2001. In order to reduce the immediate rate impact, DWR anticipated financing a part of the costs incurred at the highest rate levels by issuing bonds. Any DA customers that took bundled service during this historic period prior to DA suspension date bear responsibility for paying a fair share of costs representing that period.

No party has challenged the Commission's legal authority to hold DA customers responsible for the historic unrecovered DWR costs incurred during 2001 for DWR purchases that to serve DA customers, at least for those DA customers that took bundled utility service for some period up to July 1, 2001. Several parties representing DA interests do object, however, to imposing charges for DWR undercollections covering periods of time that DA customers were *not* on bundled service during the period that DWR incurred its undercollections.

There is also disagreement concerning whether DA customers' responsibility for costs incurred up through September 20, 2002 should be limited only to the historic undercollection, or should cover the full amount of the Bonds that are being addressed in A.00-11-038 et al. to the extent that the total proceeds from the Bonds exceed amounts required to finance the DWR undercollection. Some parties propose that this historic revenue shortfall component be recovered as a separate levelized fixed charge amortized over multiple years. Other parties propose that instead of a separate levelized fixed charge, DA customers simply pay a pro rata share of the bond charge which will be determined in A.00-11-038. Parties also dispute which categories of DA should pay for DWR undercollections. We discuss each of these issues in turn.

SCE states that these post-September 20, 2001 values understate the actual amount of DA load on SCE's system. According to information submitted to the Commission by SCE, SCE's actual DA level currently exceeds 15%. This error in DWR's assumption could have a significant impact on both the Indifference Cost calculation and the CRS. The final CRS calculation should be based on the correct levels of DA load, not only for SCE but also for all of the IOUs, reflecting the actual DA load that exists at the time of such calculation.

Essentially, DWR treats the 11.6% incremental DA load as though it was on bundled service continuously from January through September, and then switched in its entirety to DA thereafter. The 11.6% is the maximum amount of DA load that was on bundled service, but it only contributed to DWR's undercollection while receiving bundled service. Since the aggregate DA load declined to July, then increased to September, the average incremental DA load was lower than 11.6%.

Between September 1999 and January 2001, direct access levels fluctuated between 12% and 16% of total statewide electric load before dropping to about 2% by June 2001.[30] This shift reflected the return of many DA customers to bundled service during early 2001. Between July 1, 2001 and September 20, 2001, however, approximately 11% of the total load of the utilities had shifted once again from bundled service back to direct access service. This shift to direct access after July 1, 2001 resulted in a reduced bundled customer load to shoulder any uneconomic costs.

Certain parties (e.g., PG&E) propose to apply the historic undercollection to all DA customers, even those that were receiving DA service prior to July 1, 2001. While PG&E acknowledges that continuous DA customers did not purchase DWR power, it argues that DWR's purchasing activities benefited all customers within the state, including DA customers, by stabilizing power markets and preventing the state power grid from going down. Most parties propose to exempt the approximately 2% of load that to DA prior to January 17, 2001 and remained on throughout 2001 (i.e., "continuous DA).

A number of parties propose applying the bond charge to DA customers as a means of covering the historic DWR undercollection. SCE argues that the disadvantage in this approach is that the costs are not assessed on customers based on the amounts they contributed to DWR's undercollection. Customers contributed to the undercollection only to the extent they were on

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[30] See Table 1 of D.02-03-055.

bundled service. Customers who were continuously on DA did not purchase any power from DWR and thus did not cause any of DWR's undercollections. By contrast, a customer who returned to bundled service in December 2000, then again switched to DA in September 2001, would have contributed to the undercollection for the entire time until September. A customer that took bundled service for only one month (i.e., switched from DA to bundled service in June, then switched back to DA in July) would have contributed very little.

As an alternative methodology for assessing historical cost responsibility, SCE suggests calculating individual customer bills using the following methodology. First, a DWR shortfall rate would be calculated for each month as the difference between the DWR cost of power and the utility-specific remittance rate. Second, this rate would then be multiplied by the portion of the customer's energy that was supplied by DWR that month, based on the daily usage and daily DWR energy provided.

SCE acknowledges that for this methodology to work, the Commission would need to adopt it for all three utilities. If only one utility were to implement this methodology, the other utilities would receive some of the benefits of the reduction in the Bond requirements. If individual customer responsibility is assessed, then it would have to be collected in a lump-sum and the funds used to reduce the size of the Bond requirements. This methodology would also have to apply to all DA customers. If DA customers were allowed to select whether they would pay the Bond Charge in full, or pay off their individual cost responsibility and then pay only a portion of the Bond Charge, there would be a problem of adverse selection. Customers that owed only a little, or nothing, as a result of spending little or no time as a bundled service customer would choose to pay off their obligations, and avoid the portion of the

Bond Charge to recover the 2001 DWR cost undercollection. Customers that owed a lot as a result of spending a lot of time on bundled service would opt to pay the Bond Charge. The net effect would be that a cost shift could occur to the detriment of bundled service customers.

CEC proposes an alternative approach that would identify the specific costs attributable to each customer on the basis of actual determinations of the customer's status as a bundled or DA customer during the period from June 2000 to the present. CEC notes that DWR contracts have both avoidable and unavoidable elements. CEC believes that the unavoidable costs per unit can be converted into a lump sum using historic consumption levels for each customer. CEC does not know what billing systems modifications would be required to implement its proposal, but does not believe that a major change would be required over current systems.

CIU also proposes a recovery approach designed to charge each DA customer only for the portion of the period covered by the DWR historical undercollection during which the customer was taking bundled service. Each customer would accordingly pay a different charge equal to the overall levelized charge multiplied by the percentage of time that the DA customer was on bundled service. CIU witness Chalfant computed the average portion of time that DA customers were on bundled service between January 17 through September 30, 2001, representing a ratio of 74%. The resulting charge would be 0.313 ¢/kWh, billed to each customer for the percentage portion of the historical period the customer was on bundled service for the nine months between January and September 2001. (Chalfant Rebuttal (CIU) Exh. 33, p. 5.) CIU assumes amortization over a 20-year period.

In A.00-11-038 et al., EPUC claimed that a bond issuance of $8.2 billion was sufficient to recover the past DWR undercollection amount.[31] CMTA calculates that bonds issued in this amount would translate into a bond charge of 0.284 ¢/kWh. CMTA proposes that incremental direct access customers pay only that portion of the bond charge attributable to the past undercollection and that the amount appears to be less than 0.3 ¢/kWh based on the record in A.00-11-038 et al. and in this case.

CMTA proposes that the incremental DA customers' allocated share of the 2001 undercollection should be adjusted to reflect the fact that the full 11.6% increment of load did not take bundled service for the full January – September 2001 period.[32] The average level of direct access load during the January-September period was a simple average of 4.7%.[33] However, rather than using this simple average, CMTA witness Beach recommends calculating cost responsibility for direct access customers on a month-to-month basis based upon the percentage of DA load in each particular month.[34] The responsibility of DA customers for the DWR undercollection thus would be prorated based on the number of months individual customers received bundled service during the January through September 2001 timeframe and on the portion of the undercollection that DWR incurred in each month. CMTA calculated a total allocation of $687 million of the uneconomic historic costs to direct access

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31 A.00-11-038: Exh. No. 600 at Sch. 3.

32 Exh. No. 39 at 17.

33 Tr. at 842-844.

34 *Id.* at 843.

customers,[35] resulting in a levelized annual charge over a 20-year period of $2.85 per MWh (0.285 ¢/kWh).[36]

2. Claimed Double-Counting of Bond Charge

At the time of the hearings in this proceeding, CLECA calculated a Bond Charge limited to recovering the nine-month DWR undercollection (roughly 0.31 ¢/kWh based on estimates at the time). After learning more about the proposed bond offering in the Bond Charge proceeding (A.00-11-038 et al.),[37] however, CLECA now claims that imposing the Bond Charge on DA customers would risk double recovery of ongoing costs. CLECA makes this claim because DWR is sizing its bond issuance at a level that exceeds that necessary to recover its undercollection during the first three quarters of 2001. The bond proceeds will also provide money to fund several reserve accounts as required by DWR's prospective administration of its priority power contracts.

The working figure during the Bond Charge hearings for the size of the bond issuance was $11.1 billion,[38] although DWR indicates that the bond issuance may reach $11.9 billion. DWR's witness in the Bond Charge proceeding, Montague, acknowledged that the bond proceeds would be used for purposes beyond repayment of the DWR undercollection. Montague testified that this

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35 Exh. No. 39 at Table 4.

36 *Id.* at 18.

37 By ALJ ruling dated August 13, 2002, the record in the Bond Charge Proceeding (A.00-11-038 et al.) was incorporated by reference into this proceeding.

38 Bond Charge Case. (A.00-11-038 et al.) Ex. 1, at pp. 6 and 13; Ex. 106.

shortfall is about $7.3 billion.[39] Since then, the DWR has generally recovered revenues sufficient to meet its ongoing revenue requirement.[40]

This $7.3 billion shortfall has been temporarily covered by the DWR through loans from the State's General Fund and an interim loan, both of which are to be repaid out of the bond proceeds.[41] The total amount of these two loans, however, exceeds the total amount of the revenue shortfall for the initial nine-month period, roughly $10.5 billion compared to the $7.3 billion historic shortfall, an excess of more than $3 billion.[42] Consequently, DWR's Power Fund has a positive balance of more than $2 billion presently.[43]

CLECA claims that a substantial portion of the bond proceeds will be going to fund the DWR's ongoing power procurement operations, and to provide credit support for its priority contracts. Exhibit 106 in the Bond Charge case indicates that bond fund proceeds will be used to fund more than $1.7 billion of power procurement reserve accounts, rather than the historic undercollection. CLECA thus argues that the establishment of a Bond Charge for DA customers based on the full bond issuance amount is likely to result in a double recovery.

CLECA seeks a reduced Bond Charge for DA customers to reflect only the amount necessary to recover costs only associated with DWR's historic

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39 *Id.*, Montague, DWR, TR 6619.

40 *Id.*, Barkovich, Ex. 700, at p. 4.

41 *Id.*, Montague, DWR TR 6620.

42 *Id.*, Montague, DWR TR 6621.

43 *Id.*, Ex. 106; Montague, TR 6618-6620.

under-recovery of roughly $7 billion, rather than the full $11 billion. DWR indicated that a hypothetical bond offering of $8.6 billion would provide full recovery of the undercollection with funding for bond reserve accounts.[44] On this basis, CLECA contends that a bond issuance of between $8.2 and $8.6 billion would suffice to fully cover DWR's historic undercollection.

CLECA argues that the Commission could establish a reduced Bond Charge applicable to DA customers by use of the ratio of the size of the $8.2 to $8.6 billion offering to the $11.1 billion offering (or $11.9 billion, if that is the final figure) times the ¢/kWh bond charge rate established for the larger offering. In other words, if the full offering results in a rate of 0.47 ¢/kWh, the smaller offering would result in a rate of 0.36 ¢/kWh.[45] Under CLECA's proposal, this would be the Bond Charge applicable to all customers, including DA customers, for the portion of the overall bond issuance dedicated to repayment of the historic undercollection. For bundled customers, the Commission would then add an incremental Bond Charge to recover the costs of the portion of the bond issuance dedicated to support ongoing procurement activities. This is the overall revenue requirement amount, less the revenue from the 0.36 ¢/kWh Bond Charge, divided by bundled sales. The result is an all-in Bond Charge for bundled customers of approximately 0.5 ¢/kWh.[46]

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[44] This document was identified as Exhibit 3 in the Bond Charge Proceeding.

[45] ($8.6B/$11.1B) * 0.47 cents = 0.36 cents.

[46] The increment for bundled customers is the overall revenue requirement ($842 Million) less the revenue generated by the historic bond charge (0.36 cents * 175,828 GWH) or $633 million, divided by bundled sales of 152,160. The increment of 0.14 cents, when added to the historic charge of 0.36 equals the overall charge to bundled customers of 0.5 cents.

If the Commission declines to create a differential Bond Charge, CLECA asks that some adjustment of DWR CRS be made in this proceeding. CLECA also supports a proposal of SCE witness Collette to apply the excess portion of the Bond Charge to cover the entire January 2001 through December 2002 period.[47]

The IOUs, ORA, and TURN disagree with CLECA's claim that the bond charge would constitute double counting. They argue that DA customers should bear the same pro rata share of Bond charges as bundled customers.

3. Discussion

We conclude that legal authority exists for the Commission to issue an order applying a Bond Charge to DA customers to the extent they are found to bear cost responsibility for the historic portion of unrecovered DWR costs underlying the Bonds. Under the terms of AB1X, the revenue shortfall for the historic period is 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

[47] Collette, Edison, Ex. 22 at pp. 22-23.

> 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.

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.[48] This proceeding is the designated forum for the requisite Commission order addressing whether, or to what extent, such Bond Charges may or should be imposed on DA customers. The actual determination of the revenue requirement and per-customer bond charge applicable to DA customers, however, is being addressed and implemented in A.00-11-038 et al. (the "Bond Charge" phase).

As stated in D.02-02-051, the imposition of Bond Charges on the electric power sold by ESPs to DA customers would help ensure the recovery of DWR's Bond-Related Costs and thereby improve the security of the bondholders. We noted in D.02-02-051, however, that the issues associated with the imposition of Bond Charges on ESP power were too complicated and time consuming to address at that point. We placed parties on notice in D.02-02-051 that we planned to consider in a future proceeding whether to impose Bond Charges on the electric power sold by ESPs, and if so, how to do it.

Among the issues to be considered are whether Bond Charges should apply to (1) ESP power delivered to customers that have never received

[48] Rate Agreement, Section 4.3.

power from DWR, and (2) ESP power delivered by a generator that is not connected to the grid. The instant proceeding has been designated for this determination. In this order, we make no determinations relating to departing load.

D.01-09-060 was also issued to facilitate the issuance of State of California bonds at investment grade necessary to ensure the repayment of the expenditures made from the State's General Fund to pay for DWR power for the utilities' customers. These expenditures were made to help weather the energy crisis confronting all retail end-users statewide. (D.01-09-060, pp. 4 & 8; see also, Water Code, § 80000.)

By charging all affected customers, including DA load, for their respective share of the Bonds, we will be consistent with our goal of achieving bundled ratepayer indifference. We conclude that it is also economically appropriate to impose Bond Charges on those DA customers that took bundled service during the period covered by the undercollections incurred up through September 20, 2001. Since bundled customers will be paying for their share of the historic undercollections in the form of a bond charge, it is appropriate that DA customers also satisfy their obligation for a share of the historic undercollection in a similar manner. This approach is consistent with our goal of achieving bundled ratepayer indifference as a result of shifts in DA load. Bundled ratepayers would not be indifferent if they were paying for undercollections on a different basis than were DA customers.

Bond charges finance the unrecovered portion of electric power purchases undertaken by DWR. As explained in D.02-02-051, Water Code Section 80110 expressly provides that DWR is entitled to recover in electricity charges amounts sufficient to enable it to comply with Section 80134, which provides for the revenues to be pledged for support of bonds that DWR is authorized to issue pursuant to Section 80130. Water Code Section 80110 provides the Commission with broad regulatory power under Public Utilities Code Sections 451 and 701, to impose charges on retail customers to recover DWR-related costs, including a Bond Charge.

We disagree with parties claiming that imposition of the full bond charge represents double-counting. We decline to apply a reduced per-kWh charge to DA customers to exclude the portion of the Bond Charges in excess of the historic undercollection. The essential reason for DWR's selling bonds is to pay back the monies used for power purchases during 2001, but as Witness Montague stated, "in order to sell any bonds the rating agencies are requiring the funding of reserves on the power side as well."[49] This funding of reserves on the power side is necessary in part due to the terms of the DWR power contracts, which contains provisions "to the general effect that payments by the Department under the contract are to be paid or payable prior to bonds, notes, or other indebtedness of the Department secured by a pledge or assignment of the revenues of the Department under the Act and other amounts of the Fund"[50] (emphasis added).

The reserve accounts are to be maintained at certain levels, and if drawn down, are to be replenished. For example, the Bond Charge Collection Account can be tapped to provide payments of Priority Contract costs if there are insufficient amounts in the Priority Contract Account, the Operating Account

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[49] A.00-11-038, Transcript July 30, 2001, page 6622, lines13-15.

[50] A.00-11-038, Rate Agreement By and Between CDWR and the CPUC, page 4.

and the Operating Reserve Account.[51] This use of bond charge money to pay power costs would then lead to transfer of revenues from the Power Charge Accounts "to reimburse the Bond Charge Collection Account for amounts previously transferred from the Bond Charge Collection Account to the Priority Contract Account to pay Priority Contract Costs."[52]

While a condition of issuing the bonds is the establishment of a significant operating reserve, that operating reserve can be eliminated, which is likely to be when DWR's long-term contractual commitments come to an end. At that time, those reserves may be used to offset DWR's ongoing costs, thereby lowering DWR's ongoing revenue requirement.

Further, those operating reserves will be funded, not by the DWR bond issuance, but by the $2.1 billion existing power fund which has already been collected as a part of DWR's ongoing revenue requirement.[53] After bond issuance, the fund will be put into operating reserves. When it is available to be used to pay power costs and thereby reduce DWR's revenue requirement, then it will provide benefit to all who bear the DWR ongoing revenue requirement by lowering that revenue requirement at that future date.

We decline to adopt the proposal of SCE that a portion of the proceeds from the DWR bonds in excess of the undercollection amount be used to fund DA customers' obligation for DWR power charges from the date of DA suspension through December 31, 2002. Those bond funds have already been

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[51] A.00-11-038, Opening Testimony of Douglas Montague, page 8.

[52] A.00-11-038, Montague, page 8 and 9.

[53] Bond Charge proceeding, Ex. 106.

designated for other purposes as explained above, and, thus are not available to pay for DA customers' DWR's obligations during the historic period up through December 31, 2002. Bundled customers will have already paid their share of DWR power costs during the period up through December 31, 2002 and will also be required to pay their pro rata share of the full bond charge. It would violate the goal of bundled ratepayer indifference if DA customers are not required to pay both of these cost elements on the same basis as bundled customers. Thus DA customers must bear responsibility both for reimbursing bundled customers for their share of from September 21, 2001 through December 31, 2002 DWR costs as well as share in responsibility for the full bond charge on the same basis as bundled customers.

We do not find SCE's alternative proposal to be a suitable means of applying bond funds. SCE's approach would result in a mismatch in the relationship between the increased size of the Bond Charge (the difference between 0.36 ¢/kWh and 0.5 ¢/kWh) and the indifference cost associated with the DA load for the period October 2001 through the end of 2002.

DA customers are not entitled to escape, however, from sharing responsibility for the DWR bond costs. Based on the information presented by DWR, none of the proceeds are going to be used to meet DWR's ongoing costs in 2003.

We therefore conclude that DA customers should bear a proportionate share of the entire revenue requirement for the Bond Charge and not simply that portion limited to the amortization of the undercollection. Otherwise, bundled customers would have to bear both their own proportionate share of bond charges, plus a share of the DA customers' burden related to excess over the amount required to amortize the undercollection. Such a result would be unfair to bundled customers and would not achieve bundled ratepayer indifference. DWR has determined the total revenue requirement that is required to fund the bonds and specific Bond Charges are being set in A.00-11-038 et al. Since the bundled customers' share of the bond revenue requirement will be based on the full size of the bonds, DA customers should rightly bear their responsibility on a similar basis. We thus conclude that the DWR "historical costs" should be separated from DWR ongoing costs and should be recovered through the Bond Charge.

X. DA Customers Cut-Off Date for Applicability of the Bond Charge[54]

A. Parties' Positions

Parties are in dispute as to which categories of DA customers, if any, should be excluded from the Bond Charge, or at least subject to a reduced share of obligation. The range of proposals for who should or should not pay includes: (1) all DA customers; (2) customers that switched to DA after January 17, 2001; or (3) customers that switched to DA after July 1, 2001.[55] Various parties also present proposals which would assign cost responsibility on a more granular level, by disaggregating the calculation into more precise measures as they relate to the variations in individual DA customers.

DWR's modeling approach applies a uniform responsibility for historical costs to the increment of DA customer load that switched from

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[54] Imposition of Bond Charges cannot happen until this decision "final and unappealable" per Section 4.3 of the Rate Agreement.

[55] Note: We are not dealing with customers switching exemption that is subject to the limited rehearing in D.02-04-067 and is pending and no prejudgment, etc.

bundled service between July 1, and September 20, 2002. DWR assumes a total pre-July 1, 2001 DA load of 2%, and a post September 20, 2001 level of 13.62%. DWR Model Scenario 5 provides the following detailed break down of DA level of the three IOUs:

	PG&E	SCE	SDG&E
July 1, 2001 Cutoff	1.22%	0.97%	9.90%
September 20, 2001 Cutoff	14.83%	10.99%	20.10%

In Navigant's modeling calculations, the total undercollection amount is assumed to be recovered as a levelized annual charge (taking into consideration financing costs, allowances for uncollectibles, and a loan reserve) over a period of 15 to 20 years.

Certain parties such as PG&E argue all DA customers should pay both the Bond Charge and the Ongoing DWR charges because of the benefits they received through DWR's success in keeping the power grid running. SDG&E disagrees with PG&E's proposal (Exh. 41, p. 2-4) that all DA customers should pay, because the proposal fails to achieve bundled ratepayer indifference consistent with D.02-04-067. (P. 4.)

In order to make bundled customers indifferent to the increase in DA load that occurred between July 1, 2001 and September 20, 2001, SDG&E proposes that application of the DA CRS should only apply to DA customers that became active DA on or after July 1, 2001.

SDG&E has proposed that the bond charge should apply to all DA customers, including continuous DA customers, because SDG&E agrees with the findings by the Commission that all customer classes have benefited from DWR's intervention in the market (FOF 38, D.02-02-052). Certain parties have proposed that the Commission ignore this finding of benefits and exempt continuous DA based on cost causation (see, e.g., SCE Opening Brief, p. 12; Callaway Opening Brief, 18-19). SDG&E states that exempting continuous DA customers from the bond charge, however, would result in the failure of these DA customers to pay for those Commission identified benefits and therefore, the Commission should not adopt this policy.

B. Discussion

We conclude that it is reasonable for continuous DA customers (i.e., those taking DA continuously before and after DWR began buying power) to be excluded from paying either for the DWR Bond Charge or for DWR undercollections. Since the bond charge is intended to compensate for the undercollection of historic costs incurred by DWR, it is equitable that the charge bear some relationship to those groups of customers that actually purchased power from DWR at least for some portion of the period covered by the historic undercollection. DWR purchased power on behalf of the expected load of bundled customers of the IOUs. DWR did not purchase power to serve customers that took DA service continuously both before and after DWR began purchasing power in January 2001.[56] DWR Witness McDonald testified that DWR never incurred any costs to serve this continuous direct access load because DWR assumed that these customers would remain as direct access customers into the future.[57]

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[56] McDonald/DWR/Tr. 2/248-49

[57] *Id.*, Tr. 2/246-47.

DWR did not purchase short-term power supplies for continuous DA customers because DA load was not a part of the utilities' residual net short requirements. Tr. 9/1201 (Magill, SDG&E); Tr. 2/200 (McDonald, DWR). And, DWR did not purchase power for continuous direct access customers under long-term contracts

We are not persuaded by parties' arguments that continuous DA load should be assessed a bond charge solely because they benefited from DWR's purchasing of power for others, which kept the power grid operating and avoided power blackouts. While DWR played some role in stabilizing energy markets and preventing power blackouts, its purchasing program was not the only factor involved. No one has quantified the extent to which any benefit of maintaining power flows can be attributed to DWR as opposed to other factors. Thus, there is no basis to assign a specific economic monetary value to the role played by DWR. Attempting to assign a charge to DA customers based solely on indirect societal benefits would be arbitrary and speculative. Moreover, it would be unfairly discriminatory to assess a uniform bond charge among DA customers when some of them had actually consumed DWR-procured power while others had consumed none. Those DA customers that had never consumed any DWR power would unfairly bear a double burden, first for the energy they had purchased from their ESP during 2001, plus secondly, a share of the costs for DWR power that had been consumed by other customers.

We decline to adopt any of the proposals that would determine cost responsibility for historic undercollections based on pro rata allocations for the specific period of time that each DA customer took bundled service. We acknowledge that in theory, such approaches would more accurately match charges paid for DWR power consumed. Nonetheless, such an approach is not appropriate in this instance. Our stated goal is to achieve bundled ratepayer indifference. Consistent with this goal, the practices and protocols for the regulatory treatment of individual DA customers should be consistent with that for individual bundled customers. Under the utility tariffs charged to bundled customers, uniform terms and rates apply irrespective of the particular circumstances of individual bundled customers. There is no provision for bundled customers to pay lower rates merely because they may have, for example, moved into the utility service territory after DWR began procuring power and thus, did not consume DWR power for the full duration of the period covered by the DWR undercollection. This regulatory policy instead casts a much broader net and applies uniformity to broad groups of bundled customers consistent with the terms and rates or charges adopted in the respective tariff. Likewise, DA customers should be subject to the same sort of uniform regulatory protocols that apply to bundled customers in the interests of bundled ratepayer indifference.

Moreover, while the application of a uniform bond charge to DA customers without regard to exact periods each customer's bundled service does not precisely reflect cost causation, our adopted approach is consistent with D.02-02-051 in which the principles for application of the Bond Charge were articulated. In that order, we stated:

> "The Act does not require Bond-Related Costs to be recovered through charges that are imposed only on the power that is sold by DWR. Nor does the Act require the use of a particular ratemaking method to recover DWR's Bond-Related Costs or Department Costs. Therefore, the Commission may use its broad authority under Water Code § 80110 and Pub. Util. Code § 451 and § 701 to devise and

> implement the separate Power Charges and Bond Charges set forth in the Rate Agreement. . .
>
> "At the time the Act was passed into law, it was unknown how the energy crisis would unfold or how long DWR might be selling power, which suggests that the Legislature intended to provide DWR and the Commission with great flexibility in the Act to devise a means to recover DWR's revenue requirement. . . " (D.02-02-051)

In addition, as noted by SDG&E, there are practical limitations in its billing system that would make such customer-by-customer determinations of charges impractical and unduly costly. For all of these reasons, it is appropriate to apply uniform charges to DA customers subject to the bond charge in a similar manner as is being applied to bundled customers in A.00-11-038 et al.

XI. Criteria for Determining July 1 Cut-off Date for Applicability of DA-CRS

A. Parties' Positions

Certain parties argue that the measurement of DA load as of July 1, 2001 for purposes of applying DA charges in this proceeding should be based on contract execution date, and not on the date when power under those contracts actually began to flow or the first date on which such power flows were billed. These parties take issue with Navigant's modeling assumption that only 2% of total load was on DA as of July 1, 2001, and claim that there was a substantial body of DA customers who were not "physical" DA customers as of June 30, 2001 but who nevertheless possessed a legal right to obtain such service even assuming a July 1, 2001 cut-off date for new DA service. As a result, these parties claim that Navigant's indifference measure overstates the amount of DWR costs for which DA customers properly bear responsibility.

SBC Services, Inc. (SBC) argues that basing the July 1, 2001 cut off on contract execution date is the only fair measure because DA customers have no control over any other aspect of a switch to DA. SBC argues that use of the billing cycle date is inherently unfair as a cut off criterion because some DA customers that properly entered into DA arrangements prior to July 1, 2001 could be subject to 15 years worth of DA CRS costs merely because their billing cycle began on July 2nd.

SBC disputes SDG&E's claims that the administrative burdens of implementing measures to recognize a contract execution date, rather than a billing cycle date, would unduly delay the institution of a DA CRS. SBC supports the approach proposed by CMTA as a means of implementation on an expedited basis. CMTA proposes using the procedures already adopted in D.02-03-055 to administer the September 20, 2001 DA suspension date. Under those procedures, customers and ESPs are to use an independent third party to verify that a DA contract existed as of July 1, 2001, with both the customer and the ESP submitting an affidavit under penalty of perjury that the contract date is correct.[58]

B. Discussion

We find SBC's arguments to be unpersuasive. The affidavit process adopted in D.02-03-055 was intended to be the exception, not a procedure to determine the eligibility of thousands of applicants. The Commission allowed for the affidavit process only if the there was a dispute regarding the omission of a customer from the ESP-supplied list of customers with valid contracts.

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58 Exh. 39, p. 12; D.02-03-055 at pp. 20-21.

Basing the July 1, 2002 cut off on a contract date criteria is unworkable, increases implementation time and costs, and creates uncertainties and risks. Implementing such a proposal would be extremely difficult for the utility. The utility does not have information regarding contract dates. This approach would, therefore, require the utility to first attempt to obtain this information and then attempt to verify its accuracy, which would increase implementation time and costs (Ex. 55, p. 7). Risks of misconduct and uncertainty would be created, because utilizing this exemption date will require self-certification of the contract date by the DA customer and ESP. A process involving a system of self-certification of a date that has financial incentives for the DA customer and ESP could lead to misconduct. This process would also cause uncertainties in the amount of excluded load, because the amount would not be known until some time after a decision date, which would complicate the establishment of DA CRS. Therefore, it is reasonable to use the DA "active date" to define the official DA customer start date for purposes of determining whether that customer should be excluded from the CRS.

In order to exclude a customer from the DA CRS, the billing system must be able to identify the account based on available data. SDG&E recommends that the customer's DA "active date" be used as the criterion for an exemption of CRS since the customer's billing account is established based on this date and it is easily determined. This date is consistent with the costs incurred in the development of the CRS and is easily identifiable and consistent across the parties involved. SDG&E argues that using a different criterion may be feasible to determine the exclusion criteria, but the data would need to be available and tracked by the utility.

The customer's contract date cannot be used as the exemption criteria according to SDG&E since this information is not available to SDG&E. Using the date of the Direct Access Service Request (DASR) criteria also has difficulties. SDG&E argues that the criteria would need to be defined as "accepted DASR date" since "submitted DASR date" is too vague and includes DASRs which have been rejected by the utility. Most customers are not aware of their DASR submittal date since the ESP submits the DASR.

As pointed out by Ms. Osborne of SDG&E, if the DA load on July 1 was interpreted as the amount of load that had contracted for DA service, it would take months to learn how much load did qualify for the July 1 exemption.[59] This would impede the Commission's ability to implement CRS in a timely manner.

SDG&E's DASR processing system is separate from the billing system and would require special programming to pull the DASR accepted date from the DASR system and populate the billing system with this criteria as necessary to exempt these customers from the CRS. The DA "active date," is known by the customer and already exists within the billing system. This date shall be defined as the customer's official start date on DA for the exclusion from DA CRS.

The interpretation of a July 1 suspension date based on contract execution leaves bundled service customers with reduced CRS revenues to offset their costs, and it leaves the remaining DA customers worse off, since they will now have to pay a higher unit rate. For purposes of imposing charges, it is not always practical or realistic to achieve exact precision in matching each customer's charges with kWhs consumed. In this instance, we conclude that

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[59] SDG&E/Osborne, Tr. 10/1337, 1342, 1351.

reliance on billing records, as opposed to contract execution date, forms an acceptable measure for purposes of determining the cut-off for DA CRS purposes.

The standard of bundled customer indifference as prescribed in D.02-03-055 requires that there be no cost shifting due to load that migrated on or after July 1, 2001. Costs incurred are a function of when bills were rendered for service, not when contracts were executed for DA service. Thus, if a contract is dated June 2001, but the ESP did not provide the DASR to the utility until after July 1, 2001, this customer would not have become an active DA customer until after the July 1 cut off. Until this time DWR was procuring power for this customer. It was the amount of bundled service load that drove the DWR decisions on how many contracts to sign, not some unknown figure of how many customers might have had DA contracts. Accordingly, the entire bundled load on July 1 is a relevant determinant of indifference costs. The contract date, therefore, does not necessarily correspond to the load that migrated on or after July 1, 2001. We shall base the measurement criteria on the "DA active date" as proposed by SDG&E.

Another argument offered by parties to support a contract date exemption criteria is that the active date is within the control of the utility. SDG&E witness Osborne testified, however, that the active date is actually controlled by the ESP through the date it submits its customer's DASR to the utility, and therefore, is within the control of the customer through contractual requirements imposed on the ESP (Tr. 10 at 1350-1353).

XII. Ongoing DWR Operating and Portfolio Costs

A. Overview

In addition to the bond charge which covers DA cost responsibility for DWR costs through September 20, 2001, we must provide a DA CRS component for the ongoing costs that DWR has already incurred and will continue to incur subsequent to September 20, 2001. The DA CRS component to cover DWR costs subsequent to DA suspension on September 20, 2001 can be logically divided into two categories. First, a separate CRS component must be computed to cover the appropriate DA share of DWR power purchase costs for the period from September 21, 2001 through December 31, 2002. Second, another CRS component must be determined for the DA share of the prospective DWR annual costs that will be incurred beginning January 1, 2003. We must also adopt to provide for subsequent updating of costs applicable to the CRS for 2004, and annually thereafter.

The CRS component for DWR costs covering September 21, 2001 through December 31, 2002 represents the period subsequent to DA suspension but prior to institution of CRS pursuant to the instant proceeding. During this period, DWR has been collecting its revenue requirement entirely through bundled ratepayer proceeds based on power charges that were implemented in D. 02-02-052. DA customers have not been charged anything to date to cover their share of the historic costs incurred by DWR during this period. Accordingly, a separate charge must be determined to assess the requisite share of costs on DA customers covering their responsibility for this period. Because DA customers' share of costs for this historic period have already been billed and collected from bundled customers and remitted to DWR, the charges to be assessed and collected from DA customers covering this period should be credited to bundled customers as a reduction in their bills representing a rebate for amounts they have already paid. In order to achieve bundled ratepayer indifference, the charges to be collected from DA customers should be allocated among the three IOU service territories in which the DA customers reside based upon the same DWR allocation percentages that were previously adopted for this period in D.02-02-052, as modified by D.02-03-062. Likewise, the DA charges so collected should be credited to bundled ratepayers of each utility based on the same allocation percentages. The amounts credited to bundled ratepayers should also include an interest component to recognize the time value of money covering the period from September 21, 2001 until the requisite offsetting funds are collected from DA customers and credited to bundled customers.

Because the DWR costs and operations for the September 21, 2001 through December 31, 2002 period are by now essentially a matter of history, it is not necessary to deliberate over parties' various disputes over modeling forecasts of resource assumptions to compute the applicable DA cost responsibility for this period. Recorded data reflecting actual DWR operations from September 21, 2001 through December 31, 2002 can be used to calculate the applicable share of DA cost responsibility for this period. These recorded data items should be available in the DWR 2003 Revenue Requirement proceeding.

In addition to determination of the historic charge for the period between September 21, 2001 and December 31, 2002, DA customers must also be assessed an applicable power charge representing their share of DWR costs for the 12 months beginning January 1, 2003. For this purpose, we shall direct that Navigant re-run its PROSYM model consistent with the resource assumptions underlying the DWR revenue requirement and inter-utility allocations that are being implemented in A.00-11-038. Consistent with our adoption of a total portfolio approach to calculating bundled ratepayer indifference, the Navigant model should be run consistent with the methodologies we adopt in this order, as discussed below and in conjunction with any updating of URG assumptions adopted in the Procurement OIR. (R.01-10-024.)

XIII. Modeling of Ongoing DWR "Indifference" Costs

DWR/Navigant computed the costs assignable to DA for the uneconomic portion of ongoing net purchase costs for the DWR portfolio of contracts (consisting of both contract and spot purchases) for the time period October 2001 through 2010.[60] DWR describes these costs as: "(1) the net change in operating costs of the CDWR contracts, i.e., costs of power purchased minus the resale value of any excess power; and (2) the portfolio effect of averaging fixed cost power from contracts with spot market purchases." (Direct Access Exit Fee Scenario Analysis in Support of Rulemaking 02-01-022, May 17, 2002, p. 2.)

The average cost of net short power to bundled customers is calculated separately for the July 1 and the September 20 DA cut-off cases. In each case, production costs for bundled load were determined using Prosym to dispatch utility-retained generation (URG) and DWR contracts to meet hourly loads. When the bundled customer loads exceed the URG and contracts, the model assumes power is purchased at spot market prices. When must-run URG and contracts exceed bundled customer loads, the excess power is sold in the market.

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[60] Because the present value of the 2011 cost differential for the July and September cases is minimal and the differential was negative in an earlier version of the model, DWR elected to use 2010 as the end year in its calculation.

Forecasted administration and general fixed costs are added to net power purchase costs to get total costs.

The increase in average cost of net short power to bundled customers (comparing the July 1 and September 20 cut-offs) is the amount of revenue required from DA customers if the net short power costs to bundled customers are not to increase.

There are two major groups of differences between the scenarios. The original analysis was based upon the DWR's revenue requirements underlying D.02-02-052. One set of scenarios illustrates the impact of updating assumptions and data to reflect changes since the DWR filed its revenue requirements underlying D.02-02-052. Scenario 1 reflects changes in generation, load forecasts, DA percentages, transmission and distribution losses, gas prices, and updates through late April 2002. Scenario 8 includes the effect of the renegotiated contracts.

The second set of scenarios reflects the sensitivity of the DA surcharge to various factors and assumptions as specified by parties at the workshop. These simulations were intended to provide parties with a quantitative data set as a basis to perform their own analysis and present testimony regarding the appropriate basis for computing DA CRS.

The data underlying the base case drew upon the DWR 2001/2002 revenue requirement implemented by D.02-02-052[61] for the period January 17, 2001

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[61] Water Code Section 80110 authorizes DWR to determine its revenue requirement. This Commission makes no determination concerning the "just or reasonableness" of the DWR revenue requirement.

through December 31, 2002, allocated among customers in the service territories of the three utilities.

Of the various modeling scenarios performed by Navigant, parties basing their analysis on Navigant's modeling generally support Navigant's Scenario 8 as providing the most accurate basis for determining the applicable portion of DWR costs applicable to a CRS.

The longest DWR contract ends in 2013, although the vast majority of the contracted energy expires by the end of 2011. Most of the DWR/Navigant results are based on a 20-year recovery period, because this is the expected term of the bonds. The length of the period has a significant impact upon the level of the CRS. For example, for Scenario 8 the surcharge for 10-, 15- and 20-year recovery periods as calculated by DWR/Navigant is as follows:

Years	CRS ($/MWh)
20	$25.79
15	$30.45
10	$40.09

A. Areas of Dispute Relating to Forecasts

Henwood disagrees with Navigant in two forecasting major areas. The first key difference is in the assumption about new generation construction in WSCC and California in the next several years.

1. Assumptions Regarding New Generation Additions

The level of uneconomic costs is sensitive to assumptions concerning the nature and extent of new base load plant coming online because more available generation translates to lower power prices, which in turn yields higher DWR shortfalls, leading to a higher DA CRS. (See Lauckhart (Multiple Parties)

7/16, p. 663; Lauckhart (Multiple Parties) Exh. 31, pp. JRL-4 - JRL-5; Chalfant (CIU) Exh. 32, pp. 12-13.) The opposite is the case if less generation is available. DWR conceded the first day of hearings that it needed to remove 2,331 megawatts of planned capacity from its modeling. (Schiffman (DWR) Exh. 2, pp. 8-9; Schiffman (DWR) 7/10, pp. 60-64.) The impact of such a removal is higher generation prices and lower DA CRS. (Schiffman (DWR) 7/10, p. 64.) Further, it is not at all clear that these removals from DWR's assumed new generation cover the field. In Lauckhart's opinion, power plant construct will be delayed beyond the date in the Navigant model. (Lauckhart (Multiple Parties) 7/16, pp. 660-61.)

Navigant, in its modeling, assumed that significantly more new base load generation will be built than did Henwood. The Navigant assumption regarding new base load generation results in lower market clearing prices than does the Henwood approach. Market clearing prices thus drop to the point that new highly efficient power plants are not able to earn enough revenue to cover operating costs plus fixed O&M, or to provide any contribution to debt service and other fixed costs of the new power plant. Henwood claims that this assumption by Navigant is simply not credible, and that power plants will not be financed and built under these assumptions.

2. Assumptions Regarding Market Price for Surplus Power Sales

The second area of disagreement between Navigant and Henwood relates to the market-clearing price for sales of surplus power. Navigant assumes that the price that DWR will get for this sale is 50% of prevailing spot market prices for the hour of sale. Navigant provides actual DWR historical buy and sell data that shows sales prices are 50% of purchase prices. Opposing parties argue that the assumed spot price sale should be set at 100% of prevailing spot prices. DWR indicates that the impact of this price differential is to reduce the DA CRS by 0.286 ¢/kWh.[62]

Henwood challenges this assumption, however, arguing that the DWR purchases are primarily in heavy load/high priced hours while CDWR sales are primarily in light load/low priced hours. This fact would indicate why spot sale prices by DWR will be lower than spot purchase prices. Since Henwood is forecasting spot prices hourly, it does not believe it is reasonable to take a low spot price in light load hours and then assume that DWR could sell any surplus at only one half of that low price. Furthermore, if Navigant assumes that DWR buys and sells power in the same hour and that sales prices are 50% of purchase prices in that same hour, it may well be that DWR would be making its sales at the hourly spot price, but that the purchases are being made at twice the spot price. While Navigant assumes that purchases are made at spot prices and sales made at 50% of spot prices, their analysis could also lead to the conclusion that DWR sales are made at spot prices while DWR purchases are made at two times spot prices.

Navigant modelers reduced the spot price projection by comparing not just spot prices to spot prices, however, but also spot prices to balance of month, weekly, quarterly, and long-term sales. (McDonald (DWR) 7/11, p. 176; see also *Id.*, pp. 191-93, 194-95.) DWR admits that comparing such different products limits the usefulness of comparisons because products are being mixed. (McDonald (DWR) 7/11, pp. 191-92.) Another DWR witness agreed that to

[62] Exh. 32/Chalfant; p. 12, citing DWR's May 31, 2002 memo.

include such a mixture of products in reporting power sales, as is done in Table 1 of Exhibit 1 (witness Smith's DWR testimony), would be improper. (Smith (DWR) 7/10, p. 24.) Had DWR used a proper apples to apples comparison it would have found that the appropriate relationship was 100%.

Thus, parties argue that the Commission should therefore reject the 50% discount off the PROSYM forecasted price proposed by DWR. CIU urges the Commission to assume that power will be sold off system at 100% of the PROSYM forecasted spot price. (See Chalfant (CIU) ex. 33, pp. 7-8.)

Discussion

The disputes over the validity of the Henwood versus Navigant modeling forecasts must be addressed in the context of how modeling data is to be used in this proceeding. Navigant only presented its data as illustrative. The modeling conventions presented in this proceeding involves highly complex and sophisticated simulation techniques. As noted by TURN witness Marcus, today's computer models require the estimation of all the parameters on the cost of the existing system and forecasts of fuel prices the forecast of new generation to be added in the Western U.S. Because generation and price are interlinked, it had become difficult to forecast, and relatively small changes in generation can result in relatively large changes in price.

Another, even more controversial parameter involves the simulation of bidding behavior, including ways in which bidders will not follow economic theory and will bid above marginal variable costs. A modeler must choose an expected capacity withholding and bidding strategy and will obtain a different market price depending on which strategy is chosen.[63]

Within the caveats of the complexities of the assumptions underlying models such as Navigant's and Henwood's, we must determine to what extent we must rely on such models. We conclude that Henwood's assumptions regarding new generation additions appear more convincing than the assumptions made by Navigant. DWR/Navigant offered no substantive arguments to refute the alternative new generation additions assumed by Henwood, but only notes that any difference in new generation assumptions is not the sole or even primary cause of cost differences. Nonetheless, we recognize the forecasts are only as good as the underlying assumptions made. If those assumptions prove wrong in the future, the underlying forecasts will be wrong.

We have similar concerns as to the reliability of assumptions as to prices for surplus power as off-system sales. Henwood did not present convincing affirmative evidence that surplus power will be able to be consistently sold at full price.

We likewise believe that DWR/Navigant's assumption that such surplus sales can only yield a price discounted by 50% of the market price is unduly pessimistic. While Navigant based its 50% assumption on recorded transactions, recorded experience is necessarily indicative of future results. Particularly once the utilities take over administration of the DWR contracts, there is reason to believe that a higher price can be realized on surplus power sales than has been DWR's experience up until now. DWR agrees that it is

[63] See, for example, Workshop Transcript of April 12, 2002, page 268

reasonable to presume that when the utilities take over the function of selling power and more players thus become involved, the market will tend toward more efficient operation. (Schiffman (DWR) 7/10, p. 75.) DWR admitted that it was reducing the spot price projection by comparing not just spot prices to spot prices but also spot prices to balance of month, weekly, quarterly, and long-term sales.[64] DWR admits that comparing such different products limits the usefulness of comparisons because products are being mixed.[65] Another DWR witness agreed that to include such a mixture of products in reporting power sales, as is done in Table 1 of Exhibit 1 (DWR witness Smith's testimony), would be improper.[66]

We believe the most reasonable estimate, given the uncertainties involved, favors an off-system sales price closer to 100% than to 50%. For purposes of this order, however, it is not necessary to adopt a precise off-system CRS market price, since we are not relying on long-term forecasts to set CRS.

B. Categories of Costs to be Excluded to Measure "Bundled Ratepayer Indifference

1. Exclusion of 130% of Baseline Quantities

Parties' Positions

SCE and other parties representing DA interests disagree with the DWR/Navigant indifference calculation which excludes exempted load (i.e., usage below 130% of baseline by residential customers) in computing the

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64 McDonald (DWR) 7/11, p. 176; see also *Id.*, pp. 191-93, 194-95.)

65 McDonald (DWR) 7/11, pp. 191-92.)

66 Smith (DWR) 7/10, p. 24.

applicable CRS unit cost assigned to DA customers. The exempted load that DWR excludes was exempted by the Commission, pursuant to AB 1X, from the allocation and rate design for the 3¢/kWh surcharge adopted in D.01-05-064. AB X1 required that residential customers' usage below 130% of baseline not be made subject to any increases in electricity charges. The revenue shortfall was assigned to remaining bundled customers. If additional revenue shortfalls result from policies adopted by the Commission, these parties argue that the Commission will decide how to allocate and collect them. Therefore, SCE and these other parties argue that no adjustments for this exempted load should be made for purposes of DA CRS.

ORA and TURN support the DWR approach, however, inasmuch as the loads over which the bundled rate surcharge was calculated were those loads over 130% of baseline. A significant portion of the costs in excess of 130% of baseline were allocated to the commercial and industrial classes. Under CIU Witness Chalfant's proposal, DA customers would escape those costs, even though they would be paid by bundled service customers in those same classes.

PG&E argues that residential usage below 130% of baseline should not be excluded from the indifference charges. PG&E argues that since overall electricity charges do not change, references to Water Code Section 80110 are not relevant.[67] Moreover, if and when the Commission moves to "bottoms-up" charges for these customers, and if the result would otherwise be an increase in electricity charges for residential usage below 130% of baseline, then the Commission must address whether residential electricity charges must be

[67] *See, e.g.*, TURN OB, pp. 18, 22.

modified because of Water Code Section 80110. Absent these conditions, however, PG&E claims there is no basis for excluding residential usage below 130% of baseline from the non-bypassable charges being considered in this proceeding.

Discussion

We conclude that the load below 130% of baseline is appropriately exempted from the indifference calculation. When electricity charges were originally adjusted to reflect this exclusion, bundled customers paid higher charges than they otherwise would have in order to make up the shortfall caused by the 130% of baseline exclusion. In order to maintain bundled ratepayer indifference, the burden borne by bundled ratepayers to fund the 130% of baseline exclusion should not increase. Yet, with the migration of customers to DA load after July 1, 2001, the bundled customer base available to fund this shortfall shrank. In order to offset this shrinkage in customer load, the migrating DA customers must absorb the incremental effects of funding the 130% of baseline exemption. This result is achieved only by excluding the exempted load from the denominator in computing the unit cost applied to DA. Thus, we affirm the Navigant approach.

2. Long-Term Contract Only Versus Incremental Short-Term Costs

Parties' Positions

SDG&E identifies DWR "stranded" costs only as including long-term contract costs (net of revenues from surplus sales) and associated financing costs incurred on behalf of DA load that left bundled service after July 1, 2001. SDG&E argues that the inclusion of spot market purchases increases the CRS because spot prices are substantially lower than long-term contract costs. With less bundled load as a result of the DA migration after July 1, 2001, the share of low-cost spot purchases in the DWR portfolio drops and the high-cost long-term contracts weigh more heavily in the smaller overall portfolio. DA customers should be responsible for what was incurred on their behalf and not for costs incurred (or not incurred) after they departed. SDG&E argues that costs for spot market purchases made after these customers have departed, by definition, could not have been made on their behalf. Costs that were not or will not be incurred cannot be stranded. SDG&E argues that to include any costs other than long-term contract costs results in a cross-subsidy of bundled customers by DA customers.

Other parties (e.g., SCE, DWR, ORA, PG&E and CLECA) propose to include not only long-term contract costs, but also spot market and fixed costs, that is, all DWR costs incurred. They argue that the calculation must include not only DWR's long-term contracts, but also the assumed purchases to meet the remainder of bundled customers' loads in order to achieve indifference.[68] Under current circumstances, these remaining purchases are likely to be the least expensive, on average. The increase in DA displaces this lower cost power out of the bundled portfolio.

Discussion

We conclude that it is appropriate to include short-term contracts in the indifference calculation to capture the "squeeze-out" effects identified by PG&E and others. If the effects of this "squeeze out" of lower cost power are not included in the calculation, bundled customers are not indifferent to the increase

[68] Ex. 42, pp. 3-3 – 3-5.

of direct access after July 1, 2001. They lose the benefit they would have received from having this lower cost power make up a substantial amount of power used to serve them.

Since this power is the marginal source that is squeezed out by the increase in DA above the July 1, 2001, level, the parties argue that it must be included in the calculation. This is so regardless of whether DWR purchases the power, as is the case currently, or the utilities' purchase the power, as may be the case after January 1, 2003.

In its initial testimony in this proceeding, SDG&E argued that only DWR long-term power should be taken into account in calculating the DWR-related DA CRS. SDG&E's calculation thus did not take into account the "squeeze out" effect just described. However, after cross-examination by SCE and TURN isolating and illustrating this squeeze out effect,[69] SDG&E conceded that its initial approach had to be "clarified," and that its DWR calculation had to be modified. We conclude that not only DWR's long-term contracts, but also the marginal price of short-term purchases to meet the remainder of bundled customers' loads, must be taken into account in order to accurately calculate bundled customer indifference.[70]

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[69] Tr. 1188-93, 1214-20, Magill/SDG&E. The hypothetical used by SCE, and amplified by TURN, isolates the squeeze out effect by making the simplifying assumption that the change in DA load has no effect on the average price of DWR long-term power. Under this hypothesis, the squeeze out effect accounts for all of the costs that should be included in the DWR. Because SDG&E's initial approach ignored the squeeze out, it resulted in a zero DWR charge component of the DA CRS for the hypothetical.

[70] Tr. 1298-03, Trace/SDG&E.

3. Administrative & General Costs

Parties' Positions

Certain parties argue that DWR's A&G cost should not be included in the calculation of Indifference Costs. CIU argues that because the costs are fixed, the incremental direct access load is not responsible for any of these costs. SDG&E similarly argues that because fixed costs that do not change whether or not customers switch to DA or remain bundled, such costs should not be allocated to DA customers. Other parties disagree arguing that the increase in DA customers between July 1 and September 20, 2001 would result in fixed A&G costs being allocated to the fewer remaining bundled service customers. Without allocating a portion of the A&G costs to the incremental DA customers, the remaining bundled service customers would be forced to pay an increased rate to cover these costs.

Discussion

We find that fixed A&G costs should be included in the calculation to produce bundled ratepayer indifference. As noted above, by excluding fixed A&G costs from the calculation of DA CRS, these costs are entirely absorbed by the remaining bundled customers. Because fixed costs are being spread over a reduced base of bundled customers, the result is an increased per-kWh cost to bundled customers. Consequently, because their per kWh cost would increase bundled ratepayers are not indifferent to the exclusion of fixed A&G costs. DA customers' costs responsibility is being determined on an "indifference cost" principle rather than an avoided cost methodology.

C. Utility-Specific versus Statewide Surcharges

1. Parties' Positions

SDG&E, together with certain DA parties, propose that the Commission adopt a uniform statewide-levelized charge for the DWR component of the CRS, based on the Commission's adopted revenue allocation for long-term DWR contract costs. SDG&E believes that maintaining DA CRS on a statewide basis offers greater certainty and stability to DA and bundled customers throughout the state. SDG&E's proposal also moderates the impact of the DA CRS, thus keeping DA an economically viable alternative, consistent with the Commission's stated goal.[71]

SDG&E proposes an initial DA CRS of 1.22 ¢/kWh, based on a 15-year levelized annual cost, utilizing DWR/Navigant's Scenario 8, averaged across the three utilities. SDG&E computes an equivalent utility-specific CRS of 2.76 ¢/kWh, which would be more than twice as much as PG&E's 1.1 ¢/kWh. Under a non-levelized approach, SDG&E's 2004 CRS would be 5.5 ¢/kWh compared with only 2.2 ¢/kWh for PG&E.

SCE, CLECA, and PG&E, among others, advocate utility-specific CRS for DWR costs. These proposals include allocating spot market purchases zonally[72] and separate capped CRS for each utility.[73] SCE's proposal to allocate

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[71] D.02-03-055, p. 17.

[72] SCE Witness Nelson at p. 18; PG&E Witness Burns at p. 3-5 adopt the revenue allocation adopted by the Commission in D.02-02-052, that allocates net short regionally.

[73] CLECA Witness Barkovich at p. 38.

spot market purchases zonally results in higher DWR charges for SDG&E than for SCE and PG&E. This occurs because SDG&E has a relatively higher proportion of net short compared to DA load.

Under these proposals DA CRS will differ by utility either by level or duration. Where charges are either higher in one service territory versus another or applied for a longer period of time, SDG&E argues that there is an inherent inequity in the DA market where the tradeoff of DA for bundled customers in one service territory is likely a more viable alternative than for bundled customers in another.

SDG&E argues that customer-specific CRS, even though more cost based, only increase the level of instability and uncertainty for DA and bundled customers. This is a result of the significant variability in CRS that can occur across customer classes, particularly with CEC's proposal that offers customer-specific rates and different amortization periods. Regulatory objectives often must balance efficiency with simplicity, fairness and other considerations. In addition, SDG&E argues that customer-specific CRS are costly to implement and unworkable.

In its modeling runs, DWR/Navigant only developed utility specific CRS in Scenario 5 which allocates DWR power to the utilities in accordance with the methodology utilized in the development of DWR's 2001/2002 revenue requirement. That is, long-term contracts were allocated in proportion to each utility's net-short position, and additional spot sales or purchases were made zonally.

CIU also supports utility-specific charges, arguing that the Navigant modeling is not precise enough to capture all of the relevant utility-specific variables. CIU argues that the imprecision is compounded by the great differences in charges that would result among the three utilities, with SDG&E charges more than 65% higher than those for PG&E.

2. Discussion

We find the arguments of SDG&E and others unconvincing as a basis to adopt a single uniform statewide rate for DWR power charges. The adoption of utility-specific rates is consistent with the manner in which bundled customer electricity charges are set, including charges for large industrial customers that take bundled service. We have already discussed above our reasons for declining to base CRS on levelization of long-term forecasts.

We conclude that the most material rationale underlying the proposal for levelized statewide charges is mitigate the effects of an excessively large DA CRS in the SDG&E service territory that would be significantly larger than for PG&E or SCE and that would create a greater risk of making DA uneconomic in the SDG&E service territory. We recognize this concern, but we remain concerned that any cap or levelized statewide charge will violate our underlying principle of maintaining ratepayer indifference. Utility-specific charges are more consistent with established principles of cost causation and will be less likely to mask the true cost of service associated with providing service. We will not adopt levelized state-wide charges.

XIV. Proposals for DA CRS Covering Costs Other than DWR Procurement

A. Introduction

We now consider the issue of how the DA CRS component for non-DWR utility-related costs should be determined. D.00-06-034 in the Post-Transition Period Ratemaking Proceeding (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 ongoing CTC applicable to DA customers remains to be addressed in this proceeding.

SDG&E is the only utility that currently has an ongoing CTC rate in its tariffs. But this rate was established prior to the termination of the PX short-run markets, and was based on the PX price at the time. When the energy crisis occurred, theoretically that rate should have become negative owing to the very high PX prices. But ORA and SDG&E recommended freezing the existing CTC rate and to use the revenues it generated to pay down the undercollections created by SDG&E's rate freeze instituted through AB 265 and AB 43.

We now consider the parties' proposals concerning calculation of this element.

B. Parties' Positions

1. PG&E Proposal

In this proceeding, PG&E proposes to establish DA CRS to recover ongoing CTC relating to employee transition costs and uneconomic costs of qualifying facilities (QFs) and other purchased power agreements (PPAs) in place as of December 20, 1995. PG&E has proposed an "historic undercollection" charge in its 2003 General Rate Case to cover a portion of the difference between (a) PG&E utility costs since the beginning of the AB 1890 transition period, and (b) revenues received from utility customers since the beginning of the AB 1890 transition period. PG&E notes that other DA charges that have been previously authorized by the Commission are not addressed in its proposal in this proceeding.

PG&E proposes that QF capacity payments and the WAPA revenues be used to establish the above-market component of the Ongoing CTC. Thus, the cost of QF energy payments, the costs associated with PG&E's pre-December 20, 1995, non-WAPA PPAs, and the costs of PG&E's bilateral contracts would be treated as economic and excluded from Ongoing CTC. PG&E believes QF energy payments serve as a reasonable proxy for the market component in measuring CTC.

PG&E is opposed in principle with attempts to derive an explicit market benchmark proxy for purposes of measuring the above-market CTC component. PG&E argues that there is simply no reliable market benchmark at this point, given the current uncertainties regarding the market. PG&E's approach does not require determination of a separate benchmark proxy, but simply entails separating QF capacity payments and WAPA costs as the uneconomic components subject to CTC, and treating all other components as economic.

QF cost components typically consist of energy and capacity payments. The energy component is generally tied to either the "short-run avoided cost" (SRAC) methodology or to fixed energy prices, both of which have been approved by the Commission. PG&E's formula escalates a historical base SRAC energy price in connection with the change in current gas border price indices in relation to a base gas price.

During last year's energy crisis, the Commission established a pricing benchmark known as the Consumer Transition Price for QF prices consistent with the average price of the California DWR contract portfolio, which was characterized as "represent[ing] a current survey of the market for long-term supply comparable to that which is offered by QFs."[74] The 5.37 ¢/kWh five-year fixed energy price option allowed under D.01-06-015 was developed to be consistent with the requirements of D.01-03-067.

In the aggregate, the average price of PG&E's non-WAPA, pre-December 20, 1995, PPAs is well below the QF energy price just described. As such, PG&E excludes them from Ongoing CTC, as well. Because the bilaterals were not in existence on December 20, 1995, they are not a part of the Ongoing CTC.

PG&E forecasts the QF and other PPA component of its Ongoing CTC to be $404,054,000 for 2003. As shown in the Table below, PG&E proposes that its Ongoing CTC costs for 2003 be set at $405,014,000, equivalent to an average CTC rate of $0.519 ¢/kWh.[75]

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[74] D.01-03-067, p. 23.

[75] See Table 6-1 of PG&E Exhibit

PACIFIC GAS AND ELECTRIC COMPANY
ONGOING CTC

Line No.		Ongoing CTC ($000s)
1	Employee Related Transition Cost	960[76]
2	QF and other PPAs	–
3	Total QF capacity payment	482,410
4	Restructuring/PFC	25,093
5	WAPA Contract	(103,449)
6	Total QF and other PPAs	404,054
7	Total Ongoing CTCs	405,014

2. SCE Proposal

SCE proposes that the above-market costs of its Utility Retained Generation (URG) portfolio and employee-related transition costs be allocated to all customers, consistent with the Commission's direction in D.00-06-034. SCE proposes that a DA cost responsibility component be established based on the costs associated with its URG portfolio as well as any other costs identified in Public Utilities Code Section 367 which are not related to that portfolio.

SCE defines its URG portfolio to consist of nuclear, hydro, and coal generation assets as well as long-term QF and inter-utility contracts. SCE argues that both current bundled service customers, as well as those who elected DA, should equally bear cost responsibility for this portfolio.[77] SCE proposes a

[76] Employee transition costs are defined in Public Utilities Code Section 375 as costs incurred and projected for severance, retraining, early retirement, outplacement and related expenses for employees directly affected by electric industry restructuring. PG&E's current projection for employee related transition costs for 2003 is only related to Bargaining Unit Wage Protection, and is projected to be approximately $960,000 annually.

[77] SCE also proposes to include the Independent System Operator (ISO) costs associated with the operation of this portfolio in this cost responsibility.

charge applicable to all DA customers, regardless of the date they entered into DA contracts, to recover their share of the difference between the cost of the portfolio and its value under market conditions in any given year.

SCE proposes to calculate the charge associated with its uneconomic costs as the difference between the cost of the URG portfolio and its estimated value in the market. The charge would thus apply the same "stranded cost" approach the Commission previously adopted for the calculation of the Competition Transition Charge (CTC). Thus, DA customers will be responsible for the same proportional share of "stranded costs" as bundled service customers will bear. Depending on the market conditions, the market value of this portfolio in some years could exceed its costs. Under such circumstances, DA customers would receive their share of this benefit provided that, when combined with all other charges and credits to DA customers, this benefit does not result in a credit to those customers that exceeds the generation rate of their Otherwise Applicable Tariff.

In D.02-04-016, the Commission authorized 2002 revenue requirements associated with SCE's Native Load, Purchased Power and ISO Charges for SCE of $3.772 billion.[78] This revenue requirement is comprised of: (a) the operating expenses and capital-related costs for SCE's nuclear, fossil, and hydro generating stations;[79] (b) the costs of its energy and capacity purchases

[78] SCE/Jazayeri, Ex. 22, p. 40.

[79] Authorized operating expenses include fuel, SONGS ICIP, operation and maintenance (O&M), including A&G, non-income related taxes, congestion costs and other operating revenue. The capital-related costs include amounts for depreciation, return and taxes.

through QF, bilateral contracts and inter-utility contracts, including contract buyouts and scheduling and dispatching costs; and (c) associated Independent System Operator (ISO) charges.[80] SCE proposes that this revenue requirement be compared to the estimated market value of the output of SCE's URG portfolio to calculate the initial CRS to be assessed to the DA customers.

SCE proposes a methodology for determining URG market value using a benchmark price that incorporates many of the same sources as SDG&E for published market prices, applies a more detailed regression analysis. SCE also ignores some of the information available in its sources regarding off peak prices, but instead calculates an off peak price using historical data. SDG&E argues that using the available off-peak price data contained in its proposed sources would be a much simpler and more valid alternative to calculating off peak prices based on their historic relationship to on-peak prices. SCE also proposes to develop a simulated portfolio of spot market contracts that approximates its CTC generation supply profile as a means to develop market prices.

After the Commission issues a decision in SCE's 2003 General Rate Case (GRC), some of SCE's URG costs, such as the O&M costs, will likely be set on a forecast basis without a requirement for future true-ups, while other costs such as fuel-related costs continue to be subject to the balancing account treatment. The Commission ordered SCE to record its actual costs to a balancing account and to true up the URG revenue requirement based on those recorded

[80] SCE estimated that $77.0 million of the $83.6 million in ISO charges is related to SCE's generation. Adjusting the 2002 URG revenue requirement by $77.0 million results in a total non-bypassable URG revenue requirement of $3.695 billion.

URG costs in the following year. Therefore, SCE proposes to use the above revenue requirement and compare it with the estimated market value of the output of its URG portfolio to calculate the initial CRS to be assessed to the DA customers. This charge would be subject to true up as the URG revenue requirement is trued up to the actual recorded URG costs.[81] Based on SCE's proposed 3.62 ¢/kWh market benchmark, as described previously, the resulting URG market value amounts to $2.205 billion, leaving a net amount of uneconomic costs of $1.490 billion, to be allocated among all customers, including DA customers.

Assuming that some of its URG costs will be set on a forecast basis without future true ups, while other costs will continue to be subject to balancing account requirements, SCE proposes to continue to calculate an annual URG revenue requirement for determination of DA CRS. This charge would then be trued up in the following year only for those costs that are subject to balancing account treatment.

3. SDG&E Proposal

SDG&E proposes that the Commission: (a) maintain SDG&E's current CTC rates for 2003, and continue applying these rates to both bundled and DA customers, as authorized under AB 1890; (b) revise the current SDG&E accounting process to ensure that DA customers pay their approximate share of the eligible above-market utility retained generation (URG) costs through the

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[81] SCE recognizes that the non-bypassable charges for DA customers may be established for year 2003 in this proceeding. SCE will use its 2003 URG revenue requirement when it is filed with the Commission to establish the 2003 non-bypassable charge based on the methodology described herein.

CTC, as mandated by AB 1890; and (c) use market indices, as proposed by SDG&E Witness Nelson to determine the above-market costs of SDG&E's URG eligible for CTC recovery.[82]

SDG&E proposes to maintain its current combined CTC and URG rate structures for AB 265 customers until such time that the AB 265 undercollection is completely recovered. Once the AB 265 undercollection is fully recovered, SDG&E will revise its URG revenue requirement to exclude the above market portion of URG costs that will continue to flow to the Transition Cost Balancing Account (TCBA) and be recovered through ongoing CTC rates. SDG&E believes that both bundled and DA customers remain responsible for ongoing CTC charges to recover above market URG costs.

Although witness Nelson provided a revised CTC revenue requirement, representing estimated 2003 above market URG costs for eligible assets, SDG&E proposes to keep the current CTC rates in place for 2003, in the interest of rate stability. Whereas PG&E and SCE are still subject to their AB 1890-mandate rate freezes and still have bundled rates in which their CTC charges are a residual component, since July 1999, SDG&E's CTC charges have been unbundled from its other charges.

Under SDG&E's proposal, the CTC revenue requirement will continue to be allocated to AB 265 customers and AB, 43 customers in the current 60/40 ratio. Beginning in 2004, until such time the AB 265 undercollection is eliminated, the AB 265 portion of the CTC revenue requirement shall be the greater of the current authorized revenue requirement allocated to AB 265

[82] Ex. 57.

customers (approximately $70 million) or 60% of the total revenue requirement. The difference between the total above market URG estimate and the portion allocated to AB 265 customers will be the AB 43 portion of the CTC revenue requirement.

SDG&E's forecast of above-market URG costs for qualifying generation requires projections of delivered energy and actual generation cost, and a forecast of the SP15 market indices described below. SDG&E's latest projections of its URG energy and generation cost are contained in its Procurement OIR filings (R.01-10-024) for daily bilateral purchases.[83] Only the qualifying URG from that filing is used in SDG&E's forecast of CTC revenue requirements. SDG&E proposes an averaging two published market indices[84] for standard on-peak and off-peak contract prices, with an SP 15 delivery point, traded in the daily bilateral market. SDG&E claims its proposal offers the best replacement for the California PX price, which was previously used to determine the CTC generation market value. SDG&E claims that the market benchmark proposals of other parties fail to account for key aspects that influence the determination of CTC generation market value.

SONGS costs for 2003 will be determined by SONGS ICIP. Costs for SDG&E QF generation will be based on the individual QF contract costs for

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[83] See Prepared Direct Testimony of Robert Anderson in R.01-10-024, Table 2 for CTC energy and confidential workpapers on cost sensitivity for CTC cost. Note the forecast CTC costs provided in this testimony are not confidential.

[84] Those publications, both of which are subscription services, are Megawatt Daily (MW Daily), published by Platts News Service and the Dow Jones Electric Commodity Index (DJECI).

energy and capacity. This includes those QF contracts[85] that now have a five-year fixed energy price, pursuant to D.01-06-015 and D.01-09-021. For those QF contracts with energy payments based on short-run avoided costs (SRAC), SDG&E's BCAP gas price forecast was used. Costs for the PGE purchased power will include contract costs for energy, capacity and any contractual capital cost obligations. Transmission costs for delivery of the PGE energy to the ISO-controlled grid will also be included as a CTC cost.

SDG&E's forecast of its 2003 revenue requirement of $132.9 million[86] for generation that qualifies for CTC recovery is set forth below:

CTC Generation (in GWh)	5,898.4
Generation Cost in K$	$ 331,902
Less: Generation Market Value in K$	($198,984)
CTC Costs in K$	$132,918

Given the fact that the $132.9 million is a forecast is fairly close to SDG&E's currently adopted CTC revenue requirement of $115 million and in the interest of rate stability, SDG&E's recommendation is that current CTC rate

[85] These QF contracts still qualify for above market URG costs since the contract term was not extended as part of the fixed energy price negotiation.

[86] Exhibit 57, at 2 and 4.

levels be continued in 2003.[87] This position is consistent with the position of ORA that SDG&E CTC rates remain at current levels.[88]

SDG&E proposes the following prospective treatment of CTC. On a monthly basis beginning January 2003, the recorded above market URG costs for eligible assets will flow to the TCBA and be split appropriately (60%/40%) between the AB 265 and ABX1 43 subaccounts, respectively. The revenue generated from the CTC rate each month will also flow to the respective subaccounts in the same proportion as the derivation of the CTC revenue requirement described above. After 2003, SDG&E will revise its CTC revenue requirement each year in an appropriate Commission proceeding (such as the Annual Transition Cost Proceeding) to reflect the upcoming year's forecast of eligible above market URG costs plus the 12-month amortization of the prior year's balance in the TCBA. For the TCBA balance allocated to AB 265 customers, the 12-month amortization of the TCBA will not occur for a prior year overcollected balance until the AB 265 undercollection is fully recovered.

In order to continue the recovery of the AB 265 undercollection as provided by the existing CTC revenue requirement, SDG&E proposes to continue billing its electric commodity rates at their current levels. In conjunction with A.02-01-015, the total revenues generated by the URG component of electric commodity rates will be recorded to the PECA, or its successor, beginning in January 1, 2003. Pursuant to SDG&E's adopted tariffs, any overcollection in the PECA is to be transferred to the TCBA annually. Seventy percent (70%) of the

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87 Exhibit 56 at 1.

88 Ex. 50 at 5-6.

PECA is allocated to the AB 265 undercollection as that percentage reflects the approximate share of SDG&E's total bundled service customer usage (excluding direct access) subject to AB 265. As previously described, once the AB 265 undercollection is fully recovered, SDG&E will revise its URG revenue requirement to exclude the above market portion of eligible URG assets, which is being recovered as part of the CTC revenue requirement.

4. ORA

ORA's proposed ongoing CTC for PG&E is $7.59/MWh and for SCE is $14.46/MWh. SCE's proposed HPC for 2003-2004 is $25/MWh, and a similar undercollection fee could be imposed on PG&E. Thus, the ORA's combined charges for PG&E DA customers would be $62-87/MWh and for SCE DA customers would be $69-$94/MWh.

ORA presented an illustrative calculation of an ongoing CTC for DA customers using July 2001 – June 2002 costs adopted in D.02-04-016, and the 2001 – 2002 spot price used in DWR Scenario 8 surcharge calculation. TURN supports ORA's market proxy approach, using spot market purchases by DWR or the utility as the measure of market prices. In ORA's illustration, the 2001 – 2002 system average CTC rate for PG&E is $7.59/MWh (Table 5-1), and SCE is $14.46/MWh[89] (Table 5-2). The CTC rate varies by class in the illustration since transition costs have been allocated to class and rate schedule using the top 100 hours method adopted in D.00-06-034.

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[89] See Table 5-1 and 5-2; ORA Testimony

5. CMTA

CMTA takes issue with PG&E's quantification of ongoing CTC in that it only focuses on specific URG resources that are above market, such as QF contracts, but does not reduce ongoing CTC to reflect below-market resources, such as hydro. CMTA also disagrees with the market benchmarks used by other parties.

CMTA proposes using a benchmark based on the all-in costs of a new gas-fired combined-cycle power plant, which includes both variable operating and fixed capital costs. CMTA claims this is the same benchmark that the Commission endorsed in its complaint before FERC in which it seeks to modify the DWR contracts.[90] CMTA argues that such a benchmark is conservative to the extent that (1) combined-cycle plants tend to be less expensive base load resources and (2) DWR long-term contracts include a substantial amount of more expensive peaking capacity. CMTA proposes that the different natural gas prices between northern and southern California be weighted using the allocation of net short requirements met by DWR contracts. On this basis, approximately 40% of the benchmark would be weighted with northern and 60% weighted with southern California prices. CMTA argues that using a spot price benchmark would be an "apples to oranges" comparison since DWR's contracts are long-term in nature. Spot market prices are largely irrelevant to assessing the economic viability of these long term-contracts. CMTA argues that its long-term benchmark is easy to calculate and is logical

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[90] *Public Utilities Commission of California v. Allegheny Energy Supply Company, LLC et al.*, Docket No. EL02-60-000 at 32-33 (Complaint filed Feb. 5, 2002).

because many of the DWR contracts at issue in this proceeding purchase power from new combined-cycle plants in California.

CMTA's benchmark incorporates a weighted average natural gas price (40% for northern; 60% for southern California) consistent with how the DWR long-term contracts are allocated geographically.[91] The uneconomic DWR costs as determined by the use of the benchmark are then allocated across all bundled and incremental direct access loads based on each rate group's share of the highest 100 hours of system loads.

CMTA's proposes that its long-term benchmark be used to measure uneconomic URG costs. Like the DWR contracts, the URG portfolio consists of long-term resources owned by the IOUs or under long-term contract to serve the IOUs. Thus, in order to conduct an "apples to apples" assessment, a long-term benchmark is appropriate. However, because each IOU's URG portfolio is different, CMTA proposes that the URG cost components should be individually calculated and allocated for each IOU.[92]

6. CLECA

CLECA argues that combining charges developed using the DWR method with a separate CTC charge will require DA customers to significantly subsidize bundled customers. CLECA argues that it is more appropriate to look at the entire bundled portfolio to determine whether the departure of DA load has increased the costs for remaining bundled service customers. The bundled portfolio will contain some above-market power (e.g., QF contracts, DWR power)

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[91] *Id.* at 14.

[92] Exh. No. 39 at 27.

and some below-market power (e.g., utility hydro, nuclear, and coal generation). CLECA also argues that applying a CTC charge only to the above-market URG, e.g., QF contracts, again reduces the average cost of electricity for bundled customers even further because their share of the below-market URG increases at the 13.6% DA level relative to the 2% DA level. In order to avoid any subsidization, CLECA believes that the entire utility portfolio must be considered, i.e., for each utility, all URG and its pro rata share of DWR power should be combined together in determining how much DA customers must contribute to keep bundled customers indifferent.

C. Discussion

We shall implement the DA CRS relating to the uneconomic portion of utility-related costs in the following manner. We shall direct that an updated calculation of uneconomic utility-related costs be performed utilizing the updated URG and PPA/QF costs that are adopted pursuant to the Procurement OIR (R.01-10-024). Calculating ongoing CTC requires a market price. CTC was defined in D.97-06-060 and D.97-11-074 as being the difference between the utilities actual cost of a particular asset or contract and the short-term Power Exchange (PX) price. When D.00-06-034 was issued, the PX was still operating its short-term markets. In the absence of a PX price, a new market price benchmark must be established for use in calculating CTC.

The uneconomic portion of these costs shall be determined by comparing the market value of utility-related resources using a designated market proxy, as we explain below.

We appreciate the difficulties in identifying a realistic measure of a market proxy given the current unsettled state of power markets. Nonetheless, we must develop a measure in order to calculate a separate CTC charge for DA customers. Although there are advantages and disadvantages to each of the proposed approaches, on balance, we find that the use of a gas-fired combined cycle unit offers the most appropriate proxy measure. We conclude that spot price proxies are too unstable and unreliable to form the basis for a market proxy.

The demise of the California PX has reduced the size and transparency of the spot market. Even though the California ISO continues to run a real-time market for balancing energy, and bilateral market prices continue to be reported, the data is very limited.[93] Spot electric prices may become even more volatile and unpredictable because of the ISO market redesign efforts and FERC oversight.[94] FERC's existing spot market cap of $91/MWh will expire as of September 30 and will be replaced by a $250/MWh price cap.[95] Thus, in the interest of providing more stability and a cost-based approach, we conclude that a benchmark based on the long-term cost of operating a combined-cycle unit offers the best result.

We are concerned, however, that the reported values for a combined cycle proxy offered by CMTA seem rather high when compared with other parties' proposed measures. CMTA's benchmark price ranges from $43.86 to $53.75/MWh over a 10-year period. By contrast, the current market prices for

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[93] For example, publications and business information services that report bilateral market prices usually do not report hourly prices. Exh. 39 at 14.

[94] Exh. No. 39 at 14-15 (citing *SDG&E et al.*, 97 FERC ¶ 61,275 (2001)).

[95] *San Diego Gas & Electric Co. v, Sellers of Energy,* 100 FERC ¶ 61,050 (2002).

ten-year supply contracts based on actual market prices range from $40.52 to $43.53, as reported by Strategic Energy Witness Lacy.[96]

CMTA's explanation that values will vary over time does not fully satisfy our concerns as to its measures of the magnitude of the proxy. If in fact, such values vary over time, we find the alternative value for a combined cycle unit offered by ORA to be preferable since it is based on a 15-year levelized cost calculation. We shall thus adopt the combined cycle proxy value of 4.3 ¢/kWh cited in ORA's testimony as the benchmark for purposes of calculating indifference costs under this order.

We adopt the 4.3 ¢/kWh specifically for the 2003 DA CRS calculations. We emphasize that the market proxy value should be regularly updated with each annual updating of the DA CRS component for URG to reflect the most current and reliable data.

XV. CRS Mitigation: Capping or Levelizing CRS

Various parties representing DA interests propose that the Commission consider the cumulative economic impact on DA customers of imposing CRS charges, and the potential risk of making DA uneconomic for its program participants. These parties propose that the DA CRS be capped at a prescribed amount to limit the adverse economic effects on DA customers that would otherwise result from the rate increases that would be required to fully fund DA CRS, including the Bond Charges. The shortfall representing the difference between DA CRS costs and the revenues provided by DA participants would be

[96] Exh. 37, pg. 7; Tr. 6/780-81.

someone else's responsibility, at least for a while. This proposal is a classic example of a cost shift that may violate the law, which prohibits unreasonable discrimination, and may contravene sound policy considerations.

A. Legal And Policy Considerations

In a recent order the Commission has expressed the view that the DA program has value for California, and that efforts should be undertaken to avoid making DA uneconomic for the customers who participate. While the Legislature suspended DA by enacting the provisions of Water Code 80110, it did not end DA nor did it repeal or modify the provisions of AB 1890 directing the Commission to "... take actions as needed to facilitate direct transactions between electricity suppliers and end use customers."[97] The cost shift issue posed by the DA CRS cap proposal is therefore not about ending or preserving direct access as a matter of philosophy. Rather it is about the use of subsidies to prop up DA under the conditions imposed on California by the Energy Crisis. We reject the proposal for caps at this time.

The Legislature and the Governor have made it very clear that cost shifting and subsidies are not permissible devices for use in propping up DA. In his message accompanying the veto of the major DA resumption proposal in the 2001 Legislative Session,[98] the Governor said:

> I am returning Assembly Bill 9XX without my signature.

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[97] Public Utilities Code section 366.

[98] Assembly Bill 9 of the Second Extraordinary Session (Migden), vetoed on October 14, 2001.

This bill would authorize end-use customers to aggregate their electric loads as individual consumers with private aggregators or as members of their local community with community choice aggregators.

Last June, approximately two percent of the customer load in the territory served by the three investor-owned utilities (IOUs) was receiving power from direct access providers. The Public Utilities Commission (PUC) recently suspended direct access, but the percentage of load subject to direct access transactions grew to as much as 13 percent or more prior to the suspension. That growth creates a significant and unfair cost burden for those customers who continue to receive power from the IOUs and the Department of Water Resources.

This rapid growth in direct access necessitates more concise cost-containment provisions for the remaining IOU customers than those contained in this bill, and those provisions should apply to all direct access contracts.

Moreover, this bill does not clearly authorize fees to cover costs that may result when direct access customers return to service with an IOU, which would create new and unanticipated procurement obligations for the IOU. Those new procurement obligations could come about solely because the direct access provider no longer chooses to provide service to its customers because of rising electricity costs, and instead passes that burden on to the IOU and its customers.

Any efforts to allow direct access must be equitable for all stakeholders.

The Legislature has similarly expressed its intent that all customers pay their fair share of energy costs, regardless of the identity of their supplier.[99]

These policy considerations expressed by the Executive and Legislative branches militate against the use of a cap on the DA CRS to limit the ability of the utilities and the DWR to recover their costs. The legal barrier imposed by Public Utilities Code section 453, which prohibits granting unreasonable preferences to any customer or class of customer, is another obstacle for the proponents of a cap.[100] The cap proponents are explicitly contending for a rate preference in order to sustain a potentially unviable program of which they are the sole beneficiaries. Approval of the cap proposal potentially raises rates for non-participant customers, and implicates the credit of the utilities and the State of California. Again, we decline to approve a DA CRS cap at this time.

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[99] AB 117 (Migden), enrolled on August 29, 2002; AB 1755 (Soto), enrolled on August 29, 2002; AB 80 (Havice), enrolled on August 29, 2002.

[100] Public Utilities Code section 453 provides in pertinent part:

> 453. (a) No public utility shall, as to rates, charges, service, facilities, or in any other respect, make or grant any preference or advantage to any corporation or person or subject any corporation or person to any prejudice or disadvantage.
> …
>
> (c) No public utility shall establish or maintain any unreasonable difference as to rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.

B. Arguments For And Against A Cap

The complexity of the cap determination on a record that is at best incomplete for this purpose is a further obstacle to approval of a cap on the DA CRS at this time. Before a DA CRS cap can be adopted, we must first address (1) what level of cap should be set, (2) under what conditions should the level of the cap be reevaluated, (3) what rate components does it cover, and (4) in what order are costs collected? Questions also arise concerning how the deferred collections in excess of the cap should be financed, and by whom. What interest rate should be applied to the deferred charges, and how can the responsibility for funding the interest be assigned to preserve bundled ratepayer indifference?

D.02-07-032 authorized SCE to establish a "Historical Procurement Charge" (HPC) in the matter of A.98-07-003. SCE was thereby authorized to apply the HPC to DA customers by reducing the DA customers' generation credit by 2.7 ¢/kWh until the effective date of a Commission decision implementing a DA cost responsibility surcharge in the instant rulemaking (R.02-01-011). This reduction in the DA surcharge credit was intended to generate $391 million in revenues, thereby providing for equivalent contributions between bundled and DA customers for the recovery of SCE's past procurement cost undercollections.

In D.02-07-032, we noted the likelihood that DA customers would be subject to CRS in this proceeding, bond charges in A.00-11-038 et al., "tail" CTC associated with Public Utilities Code Section 367, in addition to the HPC. We observed that the "pancaking" of surcharges in different proceedings may lead to DA contracts becoming uneconomic. We noted that there was a risk of DA contracts becoming uneconomic, and stated in D.02-07-032 that "there should be a cap on the total surcharge levels imposed on DA customers (including the impact of any changes to PX credits)." But the Decision did not set a specific overall cap, "in deference to other proceedings." A recitation of the arguments and evidence in this proceeding suggests how complex determining the cap would be, and how rife with discrimination and preference the outcome.

CLECA and CMTA argue that a cap should be imposed on the maximum annual CRS that would be billed to DA customers. They claim that the combined effect of SCE's HPC, a charge to recover the DWR historical costs, a charge to recover the DWR Indifference Costs, and a charge to recover the above-market URG costs could make DA uneconomic.[101] Both parties argue that this is inconsistent with the direction of the Commission.[102] CLECA proposes caps of 2.0 ¢/kWh for PG&E and 2.25 ¢/kWh for Edison and 2.75 ¢/kWh for SDG&E. Because of SDG&E's relatively higher costs, CLECA recommends a 20-year recovery period rather than a 15-year period. It was on the basis of the figures on Table 2 of CLECA's exhibit that Dr. Barkovich concluded that its proposed caps would accommodate full recovery of the HPC, the Bond Charge and the DWR charges, with the significant caveat that recovery would be "over time." The changes CLECA anticipates in these figures does not alter its conclusion, but its numbers only represent approximations. CLECA believes the Commission should utilize the actual figures in the ongoing DWR revenue requirement proceeding to develop utility-specific DWR exit fees for 2003, and combine them with the approved Bond Charges and the HPC, if one is applicable, under an

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[101] CLECA, pp. 33, 37; CMTA, p. 28.

[102] See D.02-03-055, p. 16, "We agree with ORA and CMTA/CLECA that there are significant risks associated with an earlier suspension date as well as benefits associated with retaining a viable direct access market."

overall cap. CMTA proposes a uniform cap of 2.0 ¢/kWh be adopted, along with balancing accounts to reconcile exit fee revenues and allocated costs.

CMTA proposes that the Commission sequence the recovery of the various categories of costs under the cap with the HPC procurement costs receiving the highest priority, followed by uneconomic DWR and URG costs. Total charges would remain at the capped level until direct access customers had fulfilled their HPC obligation and were current on their contribution to uneconomic DWR and URG costs. CMTA's recommendation in this regard is consistent with the Commission's recent decision concerning SCE's HPC.[103]

SCE believes that adopting a cap is appropriate, and consistent with the Commission's intention to maintain DA as a viable customer option. SCE believes, however, that a 2.0 ¢/kWh cap is too low, and that the cap should initially be set at a level to at least allow the recovery of SCE's HPC (of approximately 2.5 ¢/kWh, though the actual rate varies by rate group) and the Bond Charge. SCE believes that setting the cap at 3.0 ¢/kWh will allow recovery of both of these items, with the condition that the first part of the revenues go to the Bond Charge (and to DWR) and the rest of the charges go to recovery of SCE's PROACT. Recovery of the PROACT will help SCE regain its credit worthy standing which was a top priority of the Settlement. Once the PROACT is recovered, SCE can reduce its rates to reflect the underlying cost of service, benefiting all customers. Setting the cap at 3.0 ¢/kWh will also accelerate the recovery of PROACT and allow the DWR above-market costs to be recovered sooner, which will benefit bundled service customers.

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[103] D.02-07-032 *In re Pacific Gas and Electric Co.* (2002).

But this avoids the issue of ongoing DWR costs and utility costs for which DA customers are responsible. The DA surcharge cap proposed for adoption in this proceeding would cover the surcharges considered in this proceeding; the ongoing CTC, the DWR Bond Charge, and the DWR power. When the Commission addresses PG&E's Historic Undercollection Charge (HUC), we must also consider how the DA surcharge cap relates to those charges.

SCE argues that it should not be required to finance any deferred collections of DWR revenue requirement attributable to DA customers in excess of a cap. Because the amounts collected for DWR power are the property of DWR, and not the IOUs, SCE argues that DWR should be the entity financing these undercollections. DWR disagrees, however, arguing that DWR has no ability to issue additional bonds or to borrow additional monies to carry shortfalls in DA CRS obligations. DWR proposes that it be paid first from any funds collected under a cap, with IOUs bearing the risk for covering their remaining costs through any remaining funds.

PG&E believes that a cap of 4 ¢/kWh would be reasonable, based on the comparative level of bundled rates that would be the alternative for DA customers. PG&E proposes that the Ongoing CTC NBC be deemed to be recovered first, then the DWR Bond Charges, leaving any shortfall attributable to the DWR NBC. PG&E also proposes that the cap be differentiated by voltage level for Rate Schedule E-20, consistent with underlying rates themselves, to reflect the differing line losses at different voltage levels.

Each third party – DWR, Edison and PG&E – is attempting to avoid the costs associated with fronting the money needed to cover the DA customers' costs. Each entity has strong arguments that they should not front and should not carry those costs; DWR because it has no legal authority, SCE because it has no financial capability. There is no basis for requiring them to subsidize the DA customers.

If a DA surcharge cap limits the revenues recovered from DA customers for the DWR revenue requirement, then DWR must either receive less than its total revenue requirement for that year from customers, or must collect the DA shortfall from bundled customers. In the latter event, however, bundled customers would pay more than was allocated to them under the indifference calculation for that year.[104]

PG&E proposes that DWR issue bonds to finance that shortfall. It is within DWR's authorized purpose for issuing bonds. Further, the $11.9 billion total bond issuance contemplated by DWR,[105] which does not take the effects of a cap into account, is well below the statutory limit of $13.4 billion set on DWR's total bond issuance.[106] This approach would require the active participation of DWR in developing the bond issuance to finance the cap. PG&E notes that DWR understands the concept, and did not raise immediate objections.[107]

With DWR funding the shortfall, customers would then be able to take advantage of the interest rate at which DWR can issue bonds. According to PG&E, under this approach, bundled customers provide the same amount each year as they would to DWR if there were no cap. DA customers pay less in the

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[104] *See*, Tr. 116-20, McDonald / DWR.

[105] Commission action at August 12, 2002, decision conference.

[106] Water Code Section 80130 (as amended by Senate Bill (SB) 1x 31.)

[107] *See*, Tr. 283, McDonald / DWR.

early years, and more in the later years as they bear responsibility for the bonds issued to finance the effects of the DA surcharge cap.

PG&E states that under the other approach, bundled customers would provide more to DWR in the early years, relative to the uncapped calculation, and less in later years. An "interest rate" would have to be established, to determine how much additional cost responsibility DA customers would have to bear in the future to "pay back" bundled customers for the extra amount they bore in the early years.

SDG&E favors levelization of annual fixed charges as a preferred approach to mitigating DA CRS, particularly given the relatively higher DWR costs experienced within its service territory. Levelization defers the impact of high-cost contract obligations in the early years to later years. SDG&E is also amenable to an overall cap on DA CRS in conjunction with levelization of the DWR component. SDG&E believes that a 2.7 ¢/kWh rate cap, encompassing the individual rate components of the DA CRS, DWR Bond Charge, HPC Charge, and ongoing tail-CTC, would more than cover its costs if its positions were adopted, as set forth below:

DWR Ongoing	1.26 cents
DWR Bonds	0.51
HPC	0.00
CTC	0.70
	2.47 cents

However, based upon updated DWR revenue requirements, SDG&E believes the Commission may well adopt a DWR Bond Charge higher than that proposed by SDG&E, pursuant to the terms of the DWR Bond Servicing and/or Rate Agreement(s). To the extent that this occurs, and results in the aggregate sum of the rate components exceeding the 2.7 ¢/kWh cap, such a cap would result in an under-recovery of one or more SDG&E rate components under the cap.[108]

SDG&E states that an under-recovery would result from the fact that, once adopted, the DWR Bond Charge becomes a non-bypassable charge that must be recovered pursuant to the DWR Bond Servicing Agreement. In much the same fashion, the ongoing tail-CTC is also a non-bypassable charge that must be recovered. For PG&E and SCE, an HPC charge is expected to remain fixed for a period of one or more years. Consequently, the only remaining element to be under-recovered is the DA CRS.

To the extent that a DA CRS revenue recovery shortfall is caused by the cap, SDG&E believes the shortfall should then be recovered from that IOU's bundled customers and tracked for that IOU. At such time that adequate headroom exists under the cap, DA customers should reimburse bundled customers for that shortfall with interest calculated at the 90-day commercial paper rate. This headroom would develop over time as a result of the completion of the collection of the HPC charge, and possible changes in the level of the DWR Bond Charge and ongoing tail-CTC.

These arguments establish that third-party financing of costs – by utilities or by DWR – are not viable options. TURN and ORA raise the further concern as to how capping the DA CRS could adversely affect bundled ratepayers who could potentially be burdened with shouldering the financing costs of excessive deferrals of DA cost responsibility as well as fronting payment of ongoing DWR costs. In effect, their argument is that creating a preference for

[108] To the extent that the aggregate components substantially exceed the 2.7 ¢/kWh, the cap would not be workable for SDG&E and should be revisited.

DA customers comes at a price for the non-participant customers, without any offsetting system benefits. There is no basis for capping the DA CRS at this time.

TURN and ORA argue that the Commission must address the risk a cap places upon bundled ratepayers. Financing any revenue undercollection produced by a cap must come from somewhere. (PG&E cross-examination, Tr. 1, pp. 15-120, McDonald/DWR.) Bundled ratepayers will pay the financing costs by default if another group or entity does not. (RT. 3, pp. 299-302, Marcus/TURN.) The financing will occur at the short-term balancing account rate, which TURN has calculated to be about 7%. (Ex. 18) Depending on the initial level of the cap and the resulting shortfall in revenues, this could result in a significant rate increase for remaining bundled service customers given the magnitude of the DA customer load.

A further consideration militating against imposing a cap is that a revenue shortfall will affect all of the Commission's initiatives to restore utility credit and support the DWR bonds. Funds remitted under the cap would be first applied to pay the bond charge, and secondly, to pay the 2003 DWR power charge. These sources would have first claim on the funds because DWR is entitled to timely reimbursement for both its bond charge and power charge. To the extent that DA customers do not pay for their share of these charges, they will have to be covered by bundled customers, and such a result would not promote bundled ratepayer indifference. Although certain parties have suggested that DWR might be able or willing to assist in financing at least some portion of DA customers' share of DWR power costs in excess of a cap, DWR has claimed that it is not able to engage in such financing. Moreover, the 2003 DWR revenue requirement has already been submitted to the Commission in A.00-11-

038 for implementation, and no source of financing has been built into that revenue requirement to accommodate the financing of a cap.

This disposition of funds would place utility cost recovery in jeopardy, and in turn undermines the ability of the Commission to effectuate the transition from DWR to utility energy procurement, which must happen by January 1, 2003.[109]

C. Issues For Further Consideration In Establishing A DA CRS Cap

We have rejected a cap at this time. However, there are several issues that might usefully be explored for use in a cap determination in the future, after the actual DA CRS has been developed and we have empirical evidence about its affect on DA customers. One consideration in setting a cap is to limit the charges imposed on DA to avoid making DA uneconomic. Yet, the evidence presented on this issue was limited to subjective judgment and anecdotal accounts of discussions with industry representatives. Based on this limited evidence, we find little basis to quantify the relationship between the level of a cap and the number of DA contracts that may become uneconomic. In the absence of good empirical evidence concerning the economic sensitivity of DA to various levels of caps, we must weigh the potential impacts of adopting a cap at either the high end or low end of parties' recommendations. Not only do we consider the adverse impacts of imposing a cap that is either too high or to low, we also consider whether effects will be experienced now or in the future. Another consideration is who will pay the interest charges to finance the excess portion of

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[109] Water Code section 80260, added by Chapter 4 of the First Extraordinary Legislative Session of 2001-02 (ABX1 1 (Keeley))

the CRS above the cap. We conclude that in order to preserve bundled ratepayer indifference, the interest charges required to finance the cap must be borne by DA customers. If bundled customers were required to fund interest charges to finance DA customers' cap, they would no longer be indifferent since those interest charges would increase total bundled customers' costs. Therefore any cap that is imposed must include within it any interest charges required to finance the excess above the cap.

The timing is also a relevant consideration in setting a cap. The potential risk to bundled customers of setting a low cap is in the potential for large undercollections to build up to a point where bundled customers would be forced to absorb at least some of the debt because DA customers would be financially unable to pay it. This risk grows as a function of time. Thus, bundled customers' exposure to this risk is felt less initially and more over time as any potential undercollection builds up. The timing affects just the reverse in the case of DA customers. The potential risk to the DA program in setting a high cap is felt more at the front end when CRS is initially established. If DA contracts become economically non-viable in fact, the risk is that those DA customers will exit the DA program. Because the level of the CRS is projected to be lower in the latter years of the DWR contracts, there might be more flexibility to develop a cap in the future as compared with today when costs are comparatively high and the risks of cost shifting are great. That circumstance may change.

Once the actual level of the DA charge is established and we have concrete empirical evidence of its impact on DA customers, the issue of a cap may become more amenable to resolution. In D.02-07-032, the Commission has stated that a cap of 2.7 ¢/kWh may be a reasonable cap. Thus, the DA community is already aware of this preliminary figure as at least a potential starting point for a cap.

Parties failed to present any convincing evidence that this preliminary assessment is at an appropriate level. Parties proposing caps as high as 4 ¢/kWh did not provide convincing evidence that a cap at this level could resolve the policy dilemma of avoiding subsidies while avoiding making DA uneconomic. Although certain comparisons were made with bundled rates to argue that a 4 ¢/kWh cap would still be less than bundled rates, and that a rate increase of that magnitude would be less than the rate increase that bundled service customers sustained in July 2001, we cannot find such a comparison to constitute proof that DA contracts could survive such a rate increase.

The other reason cited for the 4 ¢/kWh cap is to avoid the build up of excessively high DA undercollections that could become the burden of bundled customers. While we acknowledge the validity of concerns regarding the potential risk of bundled customers becoming burdened with excessively large undercollections, we view this risk as a potential problem that could grow over time.

On the other hand, a 2 ¢/kWh cap, as proposed by CLECA and CMTA, is clearly too low to cover the requisite components of CRS without triggering unduly large deferred balances. The cap must be high enough to recover the Bond Charge, the Power Charge and SCE's HPC. SCE's ability to regain creditworthy status, and resume procuring electricity to fulfill its net short, is directly linked to its ability to recover the PROACT balance. Therefore, it is important that the HPC is recovered from all DA customers in a timely manner. Pursuant to D.02-07-032, the Commission has adopted a 1 ¢/kWh HPC for SCE as part of the exit fees to be collected under the cap after a decision in this proceeding is issued.

To the extent that funds provided by DA customers under the 2.7 ¢/kWh are not sufficient to cover both the bond charge and to pay for DA customers' share of the 2003 DWR power charge, any shortfall would have to be remitted to DWR from bundled customers' funds. To the extent that any bundled customers' funds are used to remit any portion of the DA share of 2003 DWR power costs, an interest charge would have to be assessed on DA customers to reimburse bundled customers for the use of their money. The interest charges due to bundled customers for the advance of such funds would be deducted from the gross proceeds from the DA CRS paid under the 2.7 ¢/kWh cap, and credited against the bundled customers pay to DWR. To the extent that after payment of the DWR-related obligations, there were insufficient funds remaining to pay the utilities for above-market URG-related costs, the utilities would have to arrange financing for that amount. It would be an unprecedented and untenable imposition on the credit of the utilities to require them to finance a rate reduction for DA customers.

An initial cap set at the level of 2.7 ¢/kWh might represent an appropriately cautious starting point for a cap, particularly at the very beginning of instituting these charges. It would not impose any abrupt change from the level the Commission has previously referenced as possibly being a reasonable cap value. A cap at this level would promote a bridge on continuity with the preliminary assessment on this issue that the Commission made in D.02-07-032. Once the actual DA CRS is established and we have empirical evidence, as distinguished from hypothetical scenarios, about the impact on DA customers and their ability and willingness to sustain DA relationships, we can revisit the issue and determine whether a cap at the 2.7 to 3.0 ¢/kWh level affects the balance between preserving the viability of the DA program and avoiding subsidies and preferences. We reserve the option to develop a cap prospectively if we determine that such a cap will protect bundled ratepayers against the risk of excessive undercollections imposed by any cap level.

Consideration should be given to alternatives such as having DA customers provide some form of security or collateral to support the repayment of debt generated by the caps. The goal of such collateralized security will be to provide protection against bundled ratepayers bearing potential risk for nonpayment by DA customers, and to attract sources of financing for the debt under favorable arrangements.

As another measure to protect bundled ratepayers, we shall require that any DA customer that returns to bundled service must still pay off their share of the unrecovered charges resulting from the cap. We direct the ALJ to issue a procedural ruling on outstanding issues relating to the cap.

XVI. Other Issues

A. Implementation of DA CRS in Coordination with Companion Proceedings

Although this proceeding is to determine the CRS for DA customers, the final implementation of the measures adopted in this order requires coordination with other proceedings before the Commission. Specifically, with respect to DA - CRS to recover costs incurred by DWR, this proceeding must be coordinated with the proceedings in A.00-11-038 et al., in which the 2003 revenue requirement for power charges and bond charges are separately being litigated. PG&E recommends that the actual DA CRS applicable to DWR costs be determined in the DWR Revenue Requirement proceeding in A.00-11-038 et al. in order to ensure that it is based on the adopted DWR revenue requirement and inter-utility cost allocation. PG&E recommends that the Commission direct DWR to perform production simulation runs to calculate DA CRS for the DWR costs as part of the DWR revenue requirement proceeding, reflecting whatever is adopted in this case with respect to methodology and applicability of charges, and consistent with the assumptions adopted concerning forecast costs and inter-utility cost allocation.

We shall direct that the final implementation of CRS for DA customers shall incorporate the actual 2003 revenue requirements for DWR power charges and bond charges as shall be adopted in the companion proceedings in A.00-11-038 et al.

For purposes of calculating the DA share DWR power charge, the historic period September 21, 2001 through Decision 31, 2002,the DWR/Navigant model be re-run utilizing the DA "in/out" cost difference scenarios, consistent with methodological approaches we adopt in this order, as discussed above, and based on the recorded information regarding the historic costs, sales, and resource utilization for this period. The information used for this modeling exercise should be consistent with any true up of this period which is included in DWR's submittal of its 2003 power charge revenue requirement in A.00-11-038 et al.

We also direct DWR to perform an updated DA in/out model run, incorporating input assumptions consistent with those underlying the 2003 revenue requirement that is being implemented in A.00-11-038 et al., and in accordance with the methodologies and policies established in today's order. When the utilities resume purchasing power on behalf of their bundled service customers, customers should still pay the same total cost for net short power at high levels of DA market penetration as they would have paid at July 1, 2001 DA levels. Thus, utility purchases will need to be incorporated in the DWR modeling calculation. The ALJ shall issue a ruling as to a schedule for DWR to file and serve the updated model run on parties to this proceeding, and for implementation workshops, in coordination with A.00-11-038 et al. proceedings, as appropriate.

ORA recommends that employee transition costs be addressed in the Annual Transition Cost Proceeding (ATCP), the proceeding where the reasonableness of these costs is normally reviewed on a retrospective basis, with actual employee transition costs tracked in a true-up mechanism. Those costs found reasonable in the ATCP could be amortized in the subsequent year's ongoing CTC rate. We shall adopt ORA's proposal.

1. Remittance of Funds to DWR

SDG&E proposes direct remittance of revenues generated by the DWR related cost component of the DA CRS to DWR with the IOUs continuing in their role as billing agent for DWR. Remitting all revenue directly to DWR allows for immediate relief to bundled customers since their DWR charges will be based on a revenue requirement reduced by expected DA CRS revenue. SDG&E proposes that the January 2003 DWR charges for each IOU service territory be designed to recover that IOU's allocated DWR revenue requirement after the DA CRS that is expected to be received from migrated DA load is subtracted from the total DWR revenue requirement. We adopt this proposal. This revenue treatment is necessary in order to make the bundled customers of all three IOUs indifferent to the stranded DWR contract costs caused by DA migration.

Consistent with the billing, collection, and remittance processes established in D.02-02-052, the IOU shall serve as the billing and collection agent for DWR revenues applicable to DA customers. The IOU shall remit collections of DWR-related revenues from DA customers to DWR consistent with the procedures in the applicable servicing agreements that are already being applied with respect to remittance of charges for bundled customer's billings.

2. Revenue Allocation and Rate Design of Non-DWR Costs

PG&E, SCE, and ORA recommend the allocation of URG costs across all bundled and incremental DA loads based on each group's share of the highest 100 hours of system loads. This is the methodology adopted in D.00-06-034 for the allocation of ongoing transition costs associated with certain URG resources. D.00-06-034 was the final Phase 2 decision issued in the Post-Transition Electric Ratemaking (PTER) proceeding, and established revenue allocation and rate design guidelines for the same costs that are now to be recovered through DA CRS component for the ongoing CTC non-bypassable charge.

CMTA agrees with the revenue allocation recommendations of PG&E, SCE and ORA. CMTA believes this same approach should be used to allocate uneconomic DWR costs as well.[110] Both ongoing DWR and URG costs are classic "transition costs representing the above-market costs of long-term generation resources that were built or contracted to serve all customers – both

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[110] *Supra* at 21; Exh. No. 39 at 13.

bundled and direct access."[111] CMTA maintains that because the costs are so similar in nature, there are compelling reasons to use the same methodology for the allocation of these costs.[112]

The 100-hour revenue allocation methodology adopted in the Phase 2 PTER decision assigns costs to each rate class and rate group in proportion to each class' estimated total bundled and DA load during the top 100 hours of a single calendar year. The necessary allocation factors are derived using a weighted average of historic load research data from two consecutive recent calendar years (2000 and 2001), and are then rescaled to adjust for any differences between each class' share of total load during the two-year historic period relative to the test year 2003 sales forecast.

The rate design methodology for post-freeze CTC that the Commission adopted on a prospective basis in D.00-06-034, assigns all costs allocated to each rate class and rate schedule on a simple cents-per-kWh basis. PG&E argues that this approach continues to be reasonable and appropriate for setting the Ongoing CTC to be adopted for DA customers in this proceeding. Consistent with the practice already established for other similar rate components (e.g., nuclear decommissioning and public purpose program rates), PG&E recommends setting just one applicable Ongoing CTC rate for each of its principal rate classes, except that the rate would be differentiated by service voltage for those Large Light and Power customers receiving service under PG&E Schedule E-20.

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[111] Exh. No 40 at 13.

[112] *Id.*

PG&E proposes that the DA CRS for ongoing CTC and DWR costs paid by DA customers be subtracted from the total of all otherwise applicable generation-related charges determined for DA customers, prior to determining the capped DA credit amounts described in PG&E's proposed Schedule PE. The capping mechanism that PG&E proposed in the DA Credit proceeding is designed to ensure that future DA credits do not produce future undercollections of charges to be assessed to DA customers. By subtracting these revenues prior to determining capped DA amounts, PG&E believes it can ensure that the new charges established in this proceeding are truly non-bypassable.

ORA proposes that any revenues recovered from a non-bypassable charge for recovery of the above market URG costs applied to the DA customers be credited to the URG revenue requirement which is the responsibility of bundled service customers.[113] SCE agrees with this proposal.

Pursuant to the Commission and SCE's Settlement Agreement, as adopted in Resolution E-3765 and D.02-07-032, SCE will subtract the non-bypassable charges associated with recovering SCE's HPC, the DWR Bond Charge, DWR's ongoing costs, and SCE's above-market URG costs from the generation rate of DA customers' Otherwise Applicable Tariff (OAT) before it is credited to them.[114] This procedure will remain in place for the duration of the

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113 ORA, p. 5-1.

114 SCE continues to have tops-down rates, so DA customers are charged the full-bundled rate and then given a credit. Those non-bypassable charges will reduce the credit.

Rate Repayment period defined by the Settlement Agreement.[115] After the Rate Repayment period, SCE expects that the Commission will adopt a "bottoms-up" approach to calculating SCE's rate levels, and the various non-bypassable charges will appear as separate charges applicable to all bundled service and DA customers.

Discussion

The Commission in A.00-11-038 et al. authorized that transition costs to customer classes be allocated using the top-100 hours method adopted in D.00-06-034. Once that allocation is performed, the actual CTC rate for a given class is calculated by dividing that allocation of costs to that class by the kWh sales in that class. As ORA recommends, we will adopt the top 100-hour allocation factors presented in the utilities' testimony, including PG&E's update of its estimates to incorporate line loss factor for calculating the URG component of DA CRS. (Exh. 48.)

We approve PG&E's proposed treatment of DA CRS in determining DA credit amounts. We also approve ORA's proposal to credit DA CRS revenue against bundled customers revenue requirement.

B. Process for Updating the DA CRS/ True ups and Balancing Account Treatment

Parties generally agree that it is appropriate to establish a procedural process to provide for periodic updating of the DA CRS so that cost responsibility is accurately determined and so that the effects of forecasting

[115] Section 1.1(p) of the Settlement Agreement defines the Rate Repayment period as the period between September 1, 2001 and the earlier of December 31, 2002 or the date SCE recovers its procurement related obligations.

errors can be rectified. Parties offered different ideas as to how such an updating process should work, and coordinated with other Commission proceedings.

TURN proposes that the Commission set the initial DA CRS for year 2003 based upon a "backcast" rather than a forecast. TURN proposes that recorded data from the historical period beginning with the fourth quarter of 2001 through the third quarter of 2002 be used to determine the applicable DA CRS. Thus, the charge would be assessed on a 15-month lagged historical basis plus an interest allowance, with a balancing account to track actual revenues against the determined CRS revenue requirement. DWR would thereby need to produce revised DA in/out model runs incorporating such recorded data. The DA "in" scenario would still require a simulation providing hypothetical assumptions as to how DWR procurement would have looked if incremental DA load had remained on bundled service. TURN believes that backcasting is likely to be fraught with less complexity and controversy than forecasting entails.

CLECA proposes that a balancing account be established to perform two functions with respect to recovery of DWR forward costs from DA customers.[116] The first would be to true-up the differences between the realized and forecast levels of such variables as gas prices, spot market prices, and DA participation. The other purpose would be to track the difference in revenues recovered under the CLECA's proposed cap and the revenues that should have been recovered absent any cap.

SCE agrees with this concept, but disagrees with any proposal that an undercollection in this account should be carried forward, presumably by the

[116] CLECA, pp. 29-30.

utility, for the DA customers at the utility's commercial paper rate. SCE argues that by law, the amounts collected through the DWR costs are the property of DWR and not the utilities. Therefore, SCE argues that DWR should be the entity financing these undercollections. Second, at its current credit rating, SCE claims it is not possible for it to finance these balances on behalf of DA customers. Lastly, the cost of financing any balance, regardless of the entity that does it, should be entirely passed on to DA customers in order to keep bundled service customers indifferent.

PG&E characterizes the DWR charge as a simple pass-through rate that does not require the utilities to establish and administer balancing accounts. SDG&E agrees with PG&E, and does not believe that any balancing account is required or appropriate for these types of charges, since it is not SDG&E's revenues, but DWR's, that would be placed in the account. SDG&E believes the only accounting requirement should be tracking the charges and revenues associated with past and future DWR-related CRS, and that this can be accomplished through the normal accounting requirements associated with SDG&E's billing agent agreement with DWR. SDG&E anticipates it will account for the various DWR charges and the associated revenues, separately by type of charge.

PG&E proposes that the Commission simply rely upon the forecasted 2003 DWR revenue requirement, rather than separately litigate forecast assumptions for setting a 2003 DA CRS in this proceeding. PG&E proposes that the Modified TCBA (MTCBA) adopted in the PTER decision be used to track the

Ongoing CTC revenues and associated costs.[117] The MTCBA will track the cost components for QF, PPA, and employee transition costs in a fashion similar to the Post-2001-Eligible Costs section of the current TCBA. There are specific line items dedicated to each of these components. PG&E argues that nothing more complex is needed.[118]

PG&E argues that if a market measure is adopted to identify the portion of QF and other PPA costs that is to be considered ongoing CTC, then the resulting split should not be readjusted after the fact. Forecasts are regularly used by the Commission to allocate costs between classes and categories of customers. The Commission typically trues up cost forecasts for those costs that are largely outside the utility's control. But it rarely if ever trues up allocation forecasts, and should follow that same approach here. PG&E thus believes it would be more consistent with Commission practice to maintain the original cost allocation, and not perform any cost allocation true-up.

ORA also proposes the establishment of a balancing account, similar to the Transition Cost Balancing Account (TCBA), to compare the revenues received from the non-bypassable charge and the actual above market costs. Any over- or under-collection in any given year will be amortized in the rate for the following year.

SCE agrees with ORA's proposal except that no true-up should take place for the realized market price. ORA's proposal to true-up for the market price in addition to the URG costs and sales variations may be a by-product of its

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117 Ex. 42, p. 5-2.

118 Ex. 42, p. 5-2.

proposal to use DWR's forecast of spot market prices as the market benchmark. SCE's proposal to use a forward contract price with a profile similar to that of the URG output makes the market benchmark true-up unnecessary.

Discussion

We agree that an annual process is necessary to update and true-up the forecasted data underlying the DA CRS. Regular periodic true ups and updates of the DA CRS are essential to assure that the charges remain accurately aligned with more contemporary information on costs. This updating process is particularly important to ensure that any benefits derived from renegotiating more favorable terms and conditions on DWR contracts are passed through in CRS. We shall, therefore, require that the process for true-ups and updates of the DA CRS be conducted as a part of the annual DWR revenue requirements update proceeding which is currently docketed in A.00-11-038 et al. To the extent, if any, that DWR comes before the Commission for updates of its power charges more frequently than annually, any such updates shall take into account relevant DA CRS adjustments as well.

In D.02-02-052, the Commission has previously established procedures for DWR to make at least annual submissions to Commission to true up and update the applicable DWR power charges to be collected from customers. Those procedures already call for DWR to include a true up of prior period differences between forecast and actual data. We shall clarify through this order that the data submitted by DWR relating to its true up must also include requisite detail relating to costs and revenues attributable to DA load. In order to perform the true up, a back cast will need to be performed to model the difference in costs between a DA in/out scenario, along the lines of the approach that parties have used in this proceeding.

Parties expressed differing views in this proceeding concerning how a backcast might be constructed, and exactly what variables should be subject to revision in any backcast. A backcast of a DA "in" scenario requires that assumptions be made as to how DWR procurement costs would have been different if incremental DA load after July 1, 2002 had remained as bundled load. We believe that further conceptual development would be in order concerning how the backcast should be performed. We direct the ALJ to develop a further process through workshops or other appropriate forums for parties to develop protocols for a backcast process.

In D.02-02-052, we also directed the utilities each to establish balancing accounts to track revenues remitted to DWR and to segregate associated sales of URG power versus DWR power. As an additional accounting requirement, we require in today's order that each utility further segregate the tracking of revenues remittances to DWR to distinguish between DA and bundled customer collections and remittances. This segregation shall be particular important to ensure that there is no cross subsidization between bundled and DA customers with respect to the true-ups.

We order that the updating and true up of the DA CRS shall occur as a part of the DWR annual revenue requirement update. We also decline to adopt TURN's proposal that a backcast be used to set the DWR component of the DA CRS for 2003. A backcast approach would build in an ongoing disparity between the treatment of bundled versus DA customers with respect to the time frame underlying the DWR power charge. In the interests of bundled ratepayer indifference, both bundled and DA customer charges should be set based on application of a consistent measurement period. Since the forecast of DWR 2003 revenue requirement is being determined in A.00-11-038 et al., we will simply rely upon the forecast assumptions implemented in that proceeding for use in determining DA CRS. Another problem with TURN's backcast approach is that it fails to provide for a full accounting of DA cost responsibility. The backcast approach would establish charges only for previously incurred costs through 2002, but there would be no concurrent charges to compensate for prospective 2003 costs. A full accounting of cost responsibility requires that charges be established both for previously incurred costs through 2002, as well as ongoing charges to recognize prospective costs beginning in 2003. To the extent that any of these charges exceed allowable rate caps, appropriate interest charges must be assessed to account for the time value of money.

C. Billing and Tariff Implementation

Implementation of the DA CRS will require changes to a number of the utilities' tariffs. The specific changes to the tariffs can be determined following completion of the compliance workshops to compute the DA CRS cost elements, as prescribed elsewhere in this order. We direct the utilities to file compliance advice letters with all of the required tariff modifications that are necessary to implement DA CRS following completion of the compliance implementation workshops.

D. TURN's Proposal to Include the Costs of the Interruptible Program in the Distribution Component of Rates

TURN and other parties propose moving the costs of the interruptible program into distribution rates.[119] PG&E agrees that distribution rates should be modified to include the cost of the non-firm program, as directed by D.00-06-034 (Ordering Paragraph 14) in the Post-Transition Electric Ratemaking proceeding. Placing these costs in distribution rates ensures they are not avoided when a customer elects direct access. In accordance with that decision, PG&E expected

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[119] TURN OB, pp. 25-26; CFBF OB, pp. 14-15; SCE OB, p. 49.

the costs of the non-firm program, rate limiter adjustments, and power factor adjustments to be incorporated in distribution rates at the same time "bottoms-up" billing was implemented. PG&E asks that if the Commission adopts this proposal, it indicate when it would like this change made. We hereby adopt TURN's proposal. The assigned ALJ shall set a schedule to take comments as to the timing and manner of implementation.

E. Negative CTC

SCE argues that transition costs should never be negative and that a customer should not be paid for taking service, nor should the utility be placed at risk for recovery of its authorized revenue requirement, because of some unusual set of circumstances that result in an anomalous rate. (Exh. 22, p. 7.) The other two utilities did not address this issue as directly. PG&E, however, omits from its calculation elements of transition costs (i.e., irrigation district contracts) that could cause the CTC rate to become negative.[120] SDG&E's proposed accounting limits the credit to the TCBA from below market resources, meaning that CTC could only become negative if the CTC rate itself the previous year had been based on a forecast of market prices that turned out to be too high. (Exh. 56, pp. 4-6.)

ORA argues, however, that not allowing negative CTC seems to go against the netting principle articulated in Section 367(b). It states that CTC must be based on a calculation mechanism that net the negative value of all above

[120] PG&E stated that this has nothing to do with CTC ever becoming negative, but only with a desire to simplify the calculation. Nevertheless, the way PG&E has constructed its CTC rate would make it highly unlikely that CTC would ever become negative. QF capacity costs will always be positive, and the WAPA credit is unlikely to ever exceed QF capacity costs.

market utility-owned generation-related assets against the positive value of all below market utility-owned generation related assets. ORA views SDG&E's proposed accounting mechanism as a partial, but not complete, implementation of this netting principle. (RT. 8, 1129, Danforth/ORA.) It does allow credits from below market CTC eligible resources to offset the costs of above market CTC eligible resources. But that credit is limited if the credit becomes large enough to create an overcollection in the TCBA, necessitating a negative CTC rate in the following period to amortize.

Though all three utilities appear to have concerns about negative CTC, only SDG&E advanced a tangible accounting mechanism that would deal with this issue. SDG&E's proposal for the netting process was described very briefly in one paragraph of witness Schavrein's testimony, and ORA had difficulty understanding SDG&E's proposal. The implications of the proposal have not been fully explored. Moreover, a further record would need to be developed on how the accounting would be done for PG&E and SCE.[121] Since it is probably unlikely that CTC will become negative this coming year, ORA recommends that the Commission take more time to evaluate SDG&E's proposal, and also allow other parties to make their own proposals. We concur with ORA's recommendation. This issue will be taken up in a subsequent phase of this proceeding, or in another proceeding as designated by further ruling.

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121 ORA would be opposed to merely omitting from the CTC calculation resources that are below market as PG&E has done.

F. Rescission of the One Cent Surcharge from D.01-01-018 as Applicable to Direct Access Customers

In D.01-01-018, the Commission instituted what was called a temporary surcharge of a cent per kilowatt hour. As the Commission explained, "The increase will be a temporary surcharge to improve the ability of the applicants to cover the costs of procuring future energy in wholesale markets that they cannot produce themselves to serve their loads." (*Id., mimeo.,* As we discussed earlier, issues related to the impact of AB 6X and AB 1X on AB 1890 and Section 367(b) are being considered in A.00-11-038 et al. In other words, the reason for the surcharge was to pay for energy. The Commission applied that surcharge to direct access customers, even though such customers were not receiving generation service from the utilities.

The Commission later instituted an additional 3 ¢/kWh surcharge, but noting that direct access customers did not receive generation service from the utilities, exempted direct access customers from that surcharge. (D.01-05-064, *mimeo*, p. 28.)

At this point, the utilities serve bundled customers with their URG, and receive payment through normal rates. Bundled customers also receive power from DWR. Direct access customers are provided generation from neither source, although it seems quite clear that the payment by direct access customers of the one cent surcharge to date has helped defray DWR generation costs. Upon institution of CRS, direct access customers will pay what amounts to a dedicated charge component to pay for their share of DWR's power purchase program.

CIU claims there is no justification to continue the one cent surcharge after CRS commences, since it pays for generation and direct access customers will be fully paying for generation through their own contracts and CRS. CIU also claims that in calculating CRS, the Commission must provide credit to direct access customers in some way for a portion of the one cent surcharge they have been paying since January 2001, arguing that a portion of the one-cent should have gone to pay for DWR power, and not to include such a credit would result in double recovery from direct access customers.

SCE asserts, however, that it has not been assessing DA customers the 1 ¢/kWh surcharge since June 3, 2001, making CIU's request to exclude SCE's DA customers from the 1 ¢/kWh on a prospective basis moot. The advice letter implementing SCE's tariff changes authorized in D.01-05-064, Advice No. 1545-E, proposed to exclude DA customers from both the 1 and 3 ¢/kWh surcharge.

SCE argues that CIU's recommendation to credit DA customers for the amount of the 1 ¢/kWh surcharge they paid from January 2001 to June 2001 should be rejected. That surcharge was adopted by the Commission in D.01-01-018, and was appropriately assessed to DA customers until the Commission set forth its rationale for exempting DA customers from the 3 ¢/kWh surcharge and SCE filed Advice No. 1529-E to modify it calculations of the Power Exchange (PX) credit to DA customers. SCE argues that excluding those customers from the 1 ¢/kWh surcharge, as of January 2001, would violate the prohibition against retroactive ratemaking. SCE relies on Public Utilities Code Section 728 and case law to make the following argument: Public Utilities Code Section 728 provides that when the Commission finds, after holding a hearing, that the rates charged or collected by a public utility are "insufficient, unlawful, unjust, unreasonable, discriminatory, or preferential, the commission shall determine and fix, by order, the just, reasonable, or sufficient rates, classifications, rules, practices, or contracts to be thereafter observed and in force." In *Pacific Telephone and Telegraph Company v. Public Utilities Commission*, the California Supreme Court annulled a Commission decision that ordered Pacific Telephone and Telegraph Company (Pacific) to refund amounts collected pursuant to its tariffs.

The Court noted: "The Legislature has instructed the commission that after a hearing it is to make its order fixing rates to be in force *thereafter*."[122] The Commission does not have the authority to order refunds of amounts collected by a public utility pursuant to approved rates.[123] Thus, SCE argues that to retroactively alter rates charged or collected by IOUs is thus prohibited. Accordingly, SCE argues that CIU's proposal to retroactively exclude DA customers from the 1 ¢/kWh surcharge should be rejected.

PG&E argues that the CIU proposal is beyond the scope of this proceeding and so should be rejected. The issue is currently before the Commission in another forum. AReM specifically protested this aspect of PG&E Advice Letter 2119-E, which established the average 3 ¢/kWh generation surcharge in accordance with D.01-05-064 and required direct access customers to pay the 1 ¢/kWh generation surcharge. The advice letter is still pending.

In fact, in the DA Credit proceeding, PG&E proposed to include the currently excluded 3 ¢/kWh surcharge[124] in the calculation of DA customers' rates. That proposal was stricken from the proceeding.[125] CIU's proposal in this

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[122] *Id.* at 634, 650 – 655.

[123] *Id.* at 650.

[124] *See*, D.01-05-064.

[125] ALJ's Ruling On Two Motions To Strike Portions Of Pacific Gas And Electric Company's Prepared Testimony, A. 98-07-003 (DA Credit), August 5, 2002, pp. 1-2.

proceeding, made with no citation to the record, PG&E argues that it should therefore be disregarded.

Discussion

Since in the case of PG&E, the matter is already before us in a pending advice letter, this proceeding is not the proper place to resolve the issue. Further, we agree that CIU's request for a prospective adjustment is moot, at least with respect to SCE, since the charge has been removed since June 2001. Thus, no further disposition of the matter is warranted at this time.

G. PG&E's WAPA Contract

TURN argues that the costs of the WAPA contract should be included in the CRS. The WAPA contract provided significant benefits to ratepayers 20 or 30 years ago, when WAPA provided cheap power to PG&E. Now the situation has reversed, and PG&E must provide cheap power to WAPA at $22.21/MWh between now and the expiration of the contract in 2004. The contract's net costs were included in rates in 1996 and TURN thus argues that the costs are reasonably part of tail CTC. If the costs are not assigned to direct access customers, TURN argues, it is equivalent to making the unfair assumption that WAPA is supplied entirely with URG while bundled service customers must buy the DWR power.

While the contract constitutes "tail CTC," TURN argues that the appropriate valuation of the obligation is intimately tied to the DWR charges because PG&E is currently buying the power to supply WAPA from DWR as part of the net short. Its costs, therefore, must be calculated here and assigned to all customers.

Unlike the DA CRS, TURN argues that the WAPA contract should be paid for by all direct access customers, including those who were not on the system at any time after January 17, 2001. TURN divides the WAPA charge in to (1) a shortfall fee through September 30, 2001, which is part of the DWR bonds and could therefore be financed, and (2) ongoing obligations through 2004.

The existing calculation method for the rate shortfalls before September, 2001 include a pro rata share of WAPA shortfall costs for customers who moved from bundled service to direct access, but they do not include costs assignable to direct access customers who stayed on the system. The shortfall fee is calculated at $1.26/MWh of total PG&E direct access load based on actual WAPA sales during the period from January-September, 2001, using DWR's financial assumptions.

PG&E agrees with TURN that DA customers should be responsible for a share of the costs associated with the sale of power to WAPA at very low rates. In addition, TURN appears to agree with PG&E that one would use a portfolio price to determine the amount to include in the ongoing CTC determination for power provided to WAPA.[126] PG&E concurs with TURN's proposal to do a separate, post-indifference calculation adjustment to rates.[127]

TURN further proposes that WAPA costs be included on a lagged, actual cost basis.[128] PG&E disagrees with this proposal. When the Energy Cost Adjustment Clause (ECAC) was in effect, WAPA costs were treated like other costs, with WAPA costs forecast to set ECAC rates, and actual WAPA costs

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[126] TURN OB, p. 27.

[127] TURN OB, p. 27.

[128] TURN OB, p. 28.

recorded in the balancing account. There is no sound basis for building a lag into recovery of these costs. Actual costs are what will be recovered in any event.

Discussion

We adopt TURN's proposal to include the costs of the WAPA contract in the CRS calculation. As noted by PG&E, one would need to incorporate not only the WAPA revenues into ongoing CTC (as is proposed by PG&E), but also some estimate of the cost of the power being provided to WAPA in order to put TURN's proposal into effect.

Currently, DWR is providing the power to meet the WAPA contract, in the sense that DWR is providing the power to meet PG&E's net open position, and PG&E's obligations under the WAPA contract increase PG&E's net open position. However, in reality a portfolio of power is meeting the needs of PG&E's bundled customers, as well as its WAPA obligations.

Therefore, if TURN's proposal were adopted, PG&E suggests using an average portfolio price to calculate the WAPA component of ongoing CTC. The cost would be recorded as the adopted portfolio price multiplied by actual WAPA volumes, and that same amount would also be recorded as revenue against PG&E's bundled customers' costs of power. We concur with the approach suggested by PG&E. We direct that in the final calculations to compute the appropriate 2003 costs to include in the CRS for PG&E that WAPA costs be included on this basis.

H. Additions to DA List

Strategic Energy asserts that the suspension decision should be "clarified" so that some additional customers can be added to the "October 5" list; and second, Strategic Energy argues that the switching exemption should be "modified" to allow chain retailers to add additional contracts to existing DA contracts. These implementation issues are beyond the scope of this proceeding, and so they should not be addressed here.[129]

Strategic Energy has not provided any record evidence to support its recommendations to expand the scope of allowable migration to DA, and the Commission should not adopt such changes without ample supporting evidence.

XVII. 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.

Findings of Fact

1. The change in DA load levels between July 1 and September 20, 2001 results in an increase in the average cost of power for remaining bundled customer because total uneconomic costs are spread over a smaller sales base.

2. D.02-03-055 determined that as a condition of retaining the DA suspension date of September 20, 2001, a surcharge must be imposed on DA customers sufficient to make bundled customers economically indifferent between a DA suspension date of July 1 versus September 20, 2001.

3. The computer simulations performed by Navigant and Henwood provide a reasonable framework for analyzing the cost shifting effects based upon

[129] Any issues involving the limited rehearing of D.02-03-055 will be addressed in a separate order but not in today's decision.

inclusion versus exclusion of incremental DA load levels at July 1 versus September 20, 2001.

4. The cost shifting effects caused by the incremental change in DA load represents the increase in the average cost of net short power to bundled customer due to the migration of customers from bundled to DA load between July 1 and September 20, 2002.

5. The cost differential described in the preceding FOF represents the portion of the DWR revenue requirement incremental DA customers would need to pay to avoid cost shifting to bundled customers.

6. The total cost of generation used to serve bundled customers is the combined weighted average cost of both URG and the DWR power.

7. DWR power has been, on average, more expensive than the weighted average cost of URG power, to date.

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

9. AB 1X provides for DWR to collect revenues by applying charges to the electricity that it sells as a direct obligation of the retail end use customer to DWR.

10. Consistent with AB 1X, DA customers that took bundled service prior to July 1, 2001 are responsible for paying a share of the DWR revenue requirements, including both previously incurred costs as well as an ongoing cost component.

11. For previously incurred costs, DWR has not yet received full payment, and the State of California is now finalizing the sale of bonds to finance DWR's prior undercollections.

12. The DWR revenue requirement applicable to bond charges is currently being determined in A.00-11-038 et al.

13. Under the CLECA total-portfolio approach, the costs of both DWR and the URG resources are relevant to determining a total level of indifference costs.

14. Both the DWR and the URG costs for the pre- and post-DA migration scenarios are available from the DWR supplied spreadsheets.

15. Once the total indifference cost level is determined, the DWR portion of that indifference cost can be identified by calculating a cost for the IOUs' URG and subtracting that from the total portfolio indifference cost.

16. A separate DA CRS cost component needs to be determined, representing the portion of the portfolio supplied from URG resources which should incorporate a calculation of URG costs in excess of the market proxy as adopted in this order.

17. The URG-related cost component of the DA CRS needs to be separately identified because continuous DA load will be charged only this component, but not the DWR-related components.

18. Among the potential sources for a market proxy offered into evidence, the gas-fired combined cycle represents the most appropriate choice for use in determining an above-market URG component of the DA CRS.

19. The values offered by CMTA to represent the gas-fired combined cycle proxy appear high in relation to proposed values offered by other parties.

20. The combined cycle proxy value of 4.3 ¢/kWh offered by ORA, representing a 15-year levelized cost estimate from a California Energy Commission study provides the most conservative combined cycle proxy value offered in this proceeding.

21. In the interests of achieving a reasonably accurate representation of the market proxy value on a going forward basis, provision needs to be made for periodic updating of the market proxy values to reflect the most contemporaneous data.

22. As a basis to analyze the cost-shifting impacts of migrating DA load, and to develop DA CRS proposals, computer modeling simulations were performed by Navigant Consulting, Inc. and Henwood.

23. Although Navigant and Henwood employed different forecast assumptions, both used Henwood's Electric Market Simulation System and accompanying database, and both used Henwood's production simulation model, PROSYM.

24. PG&E, SCE, SDG&E, and ORA all base their CRS calculations on the Navigant Scenario 8 model run, while CLECA, CIU, and CMTA all base their CRS calculations on Henwood base Case model run.

25. Henwood modeled a "base case" representing a revision of Navigant's base case, updated to reflect Henwood's assumptions, resulting in higher estimates for the years 2002 through 2011 by$1.96 billion compared to Navigant modeling, thus resulting in a lower DA CRS.

26. Henwood identified a variety of modeling errors and inconsistencies in Navigant's initial computer runs, many of which were corrected in updated versions of Navigant's runs.

27. For purposes of measuring the cost shifting effects of DA load migration, it is appropriate to exclude demand attributable to usage below 130% of baseline by residential customers, to include incremental spot market purchases, and to include fixed administrative and general costs.

28. DWR incurred an undercollection for costs it incurred during the period from inception of its power purchase program on January 17, 2001 through the period when DA was suspended on September 20, 2001.

29. Neither bundled ratepayers nor DA customers have yet paid for the undercollection of costs incurred up through September 20, 2001.

30. The state of California is finalizing plans for the sale of long term bonds to cover the historic undercollection of DWR costs.

31. It does not result in double counting for DA customers to pay both for a pro rata portion of the full Bond Charge revenue requirement and for DWR power charges.

32. It would conflict with the Commission's mandate to achieve bundled ratepayer indifference if bundled ratepayers were required to pay a bond charge based on DWR's total revenue requirement while in DA customers only paid the fraction of the Bond revenue requirement related solely to amortization of the historic undercollection.

33. There would be a significant magnitude of cost-shifting if DWR costs and utility-related generation costs were borne solely by bundled service customers, and direct access customers were not required to pay a portion of these costs that were incurred for their benefit.

34. The Commission has previously stated in D.02-07-032 that a cap of 2.7 ¢/kWh may be reasonable for purposes of mitigating DA CRS that might otherwise increase to levels that would make DA uneconomic.

35. No party provided convincing affirmative evidence concerning the quantitative relationship between various levels of caps and the extent to which DA contracts would likely be rendered uneconomic.

36. Neither a cap as high of 4 ¢/kWh or as low as 2 ¢/kWh has been shown to be warranted as an initial starting point for DA CRS purposes.

37. Consistent with the policy statements of the Governor, the Legislature and this Commission that bundled ratepayers should remain indifferent to the DA program, DA customers should be responsible for the costs identified as theirs through the evidentiary process

38. Creation of a cap of any level on DA CRS would be arbitrary and would result in shifting of costs to bundled service customers.

39. As long as the Commission retains the flexibility to increase the cap in the future as deemed necessary to effectuate DA in the future without cost shifting, the interests of DA participants and non-participants (bundled service customers) are best balanced by assigning their share of costs to DA customers without an arbitrary cap.

Conclusions of Law

1. In implementing AB 1X, the Commission in D.01-09-060 suspended the right to enter into direct access contracts or arrangements after September 20, 2001.

2. The implementation provisions set forth in this decision are reasonable and consistent with our determinations in D.02-03-055 that suspended the right to enter into direct access contracts or arrangements as of September 20, 2001.

3. In order to achieve bundled ratepayer indifference as intended by D.02-03-055, bundled rates should neither increase nor decrease solely as a result of the migration from bundled to DA load between July 1 and September 20, 2002.

4. In D.02-04-067, the Commission expressly modified D.02-03-055 to make clear that the CRS will take into account recovery of relevant non-DWR costs and

that DA customers will be held responsible for such costs as required by AB 1X and other statutes, for example, AB 1890.

5. Determinations in this order concerning the application of uneconomic URG-related costs as part of the DA CRS are subject to any subsequent determinations the Commission may make in other proceedings where the impact of AB 1X and 6X are being examined as they relate to AB 1890.

6. Under Public Utilities Code Section 701, the Commission has broad authority to regulate public utilities and to "do all things…which are necessary and convenient in the exercise of such power and jurisdiction."

7. Consistent with its broad authority to regulate, together with Sections 451 and 453 prohibiting discriminatory ratemaking, bundled customers may not be arbitrarily charged for obligations which rightfully are the responsibility of DA customers, directly or indirectly.

8. A cap on the DA CRS would create an undue preference in violation of Public Utilities Code section 453.

9. Within its broad statutory authority, the Commission has specific authority to establish charges for the collection of costs incurred by DWR pursuant to AB 1X applicable not just to bundled customers, but also applicable to DA customers to the extent that DWR purchased power on their behalf or for their benefit.

10. Legal authority exists under the broad provisions of Public Utilities Code Section 701 and the provisions of D.02-02-051 for a Commission order applying the DWR Bond Charge to DA customers to the extent they are found to bear cost responsibility for the historic period during 2001 that DWR was incurring undercollections for its power procurement.

11. As prescribed in D.02-02-051, the Commission has an obligation to impose charges on electric customers sufficient to compensate DWR for its costs, including payment of DWR bond principal and interest payments.

12. It is consistent with the goal of achieving bundled ratepayer indifference as prescribed in D.02-03-055 for DA customers to share in the obligation for payment of principal and interest on the DWR bonds on a pro rata basis along with bundled customers.

13. As determined in D.02-02-051, the Commission is not necessarily required to impose DWR bond-related charges only on the power that is sold by DWR, but is given great flexibility to devise means to recover DWR's revenue requirements.

14. The DWR Bond Charge should be imposed on all DA customers except for those that have been on DA continuously both before and since DWR began procuring power under AB 1X.

15. Consistent with the provisions of the Water Code, DA customers that took bundled service prior to July 1, 2001 are responsible for paying a share of the DWR revenue requirements, representing both previously incurred costs as well as an ongoing cost component through the duration of the DWR power contracts.

16. The criterion for determining DA status for DA CRS billing purposes should be the "DA active" date as contained in utility billing records, not contract execution date.

17. Legal authority exists for imposing charges on all DA customers for their share of the uneconomic utility-related costs.

18. DA CRS should be established on a utility-specific basis rather than on a uniform statewide basis to be consistent with cost-based principles of ratemaking

and to avoid cross-subsidizing customers' in higher-cost service territories by customers in lower-cost service territories.

19. Because of the uncertainties and lack of reliability regarding the long-term forecasts underlying the modeling performed by Navigant and Henwood in this proceeding, it is not appropriate to set a DA CRS based upon a levelized fixed charge approach.

20. A one-year-ahead forecast should be used as the appropriate time frame to use for setting DA CRS.

21. Inconsistency in the use of forecast assumptions to establish DA CRS versus those used in the DWR revenue requirement proceeding in A.00-11-038 et al. would result in either under or over recovery of the respective shares of DWR costs from bundled and DA customers, and our goal of bundled ratepayer indifference would be undermined.

22. Since the DWR power charges applicable to bundled customers is being determined in A.00-11-038 et al., the assumptions underlying the calculation of DA CRS should be consistent with the 2003 DWR/Navigant modeling underlying the revenue requirement implemented in the A.00-11-038 et al. proceeding.

23. In the interests of consistency in the establishment of DWR power charges allocated between bundled customers and DA customers for (1) the historic period of September 21, 2001 through December 31, 2002; and (2) the prospective period of calendar year 2003, the final determination of these charges should be performed using the forecast resource assumptions underlying the DWR revenue requirement being implemented in A.00-11-038 et al.

24. Since Navigant is responsible for running the model in the determination of the DWR revenue requirement in A.00-11-038 et al., it would not promote

consistency to rely on the charges computed under the Henwood base case in this proceeding for purposes of computing a DA CRS.

25. The charges assigned to DA customers for DWR costs covering the historic period of September 21, 2001 through December 31, 2002 should be consistent with the assumption that were applied in setting power charges for bundled customers in D.02-02-052, subject to any true ups or adjustments applicable to this historic period being implemented as part of the DWR 2003 revenue requirement proceeding in A.00-11-038 et al.

26. For purposes of calculating the URG-related component of the DA CRS, each of the utilities should utilize the 2003 generation cost data submitted in this proceeding, subject to any updated data that may be adopted in the Procurement OIR (R.01-10-024).

27. The URG component for DA CRS purposes shall be computed as the incremental costs after applying the market benchmark proxy as adopted in this proceeding to URG resources. This element of the DA CRS shall be applied to the portion of the total portfolio that is supplied by URG sources.

28. The market proxy for purposes of computing the above-market URG component of the DA CRS for 2003 should be based on a gas-fired combined cycle plant and should incorporate a value of 4.3 ¢/kWh based on a 15-year levelized cost estimate as reported in ORA's testimony, referencing a California Energy Commission study.

29. The value adopted for the market proxy adopted for purposes of the 2003 DA CRS calculation should be subjected to regular updating with each annual revision of the DA CRS based on the most updated and reliable information available at the time.

30. A compliance workshop should be held in coordination with proceedings in A.00-11-038 et al. at a time to be scheduled by ALJ ruling for the purpose of performing a revised run of the DWR/Navigant model and implementing the necessary calculations to place into effect the DWR power charges to be remitted (1) by DA customers versus (2) bundled customers for the above-referenced time periods. The workshop shall also be used to compute the URG-related component of the DA CRS.

31. A compliance workshop to establish procedures for verification of Prosym and the Electric Markets Simulation System should be held a time to be scheduled by ALJ ruling.

32. The revised computer model run should provide a revised calculation of the DA in/out scenarios that similar to that run on Navigant Scenario 8, but updated to reflect the resource assumptions underlying the DWR revenue requirement being implemented in A.00-11-038 et al., and applying the methodology for computing the DA in/out scenarios consistent with the positions adopted in the instant order.

33. Since bundled customers have already been remitting funds to DWR for the period since September 21, 2001 forward which includes the portion of costs for which DA customers are responsible, bundled customers are entitled to a credit, including interest, equal to the DWR power charges that will be assessed on DA customers covering this historic period as determined in this order.

34. The issue raised by CIU regarding revocation of the one cent surcharge is more appropriately addressed in the advice letter filing of PG&E. For SCE, the issue is moot to the extent that the charge has already been eliminated on a prospective basis.

35. Provision should be made for at least annual updating and true ups of the DA CRS for each utility to be implemented in conjunction with the annual DWR revenue requirement update proceeding. Establishing a cap on DA CRS may be considered at the first annual update as determined by Assigned Commissioner Ruling.

36. Provision should be made for the utilities to maintain tracking accounts to permit segregation of the revenues collected and remitted to DWR as between bundled customers and DA customers.

37. 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 Southern California Edison Company (SCE). Pacific Gas and Electric Company (PG&E), and San Diego Gas & Electric Company (SDG&E).

2. A Direct Access Cost Responsibility Surcharge mechanism is hereby adopted applicable to designated direct access customers in the service territories of PG&E, SCE, and SDG&E, composed of the following elements:

   a. DWR Bond Charge, covering cost responsibility for the period from the inception of DWR's power purchase program through September 20, 2001, the suspension date of Direct Access.

b. DWR Power Charge, covering the historic period from September 20, 2001 through December 31, 2002.

c. DWR Power Charge, covering the prospective period for the Calendar Year 2003.

d. Utility-retained generation component applicable to above-market costs.

3. The DA CRS shall be subject to updating and true up on at least an annual basis in accordance with the processes and procedures as adopted below.

4. The DWR Bond Charge applied to all DA customers, except those that were continuously taking DA service both before and after DWR began its power purchase program. "Continuous" DA customers shall be defined to include those that have been taking DA service continuously both before and since January 17, 2001 (in the PG&E and SCE service territories) or February 7, 2001 (in the SDG&E service territory).

5. The DWR Bond Charge portion of the DA CRS shall incorporate a pro rata share of the full Bond Revenue Requirement as is being determined and implemented in A.00-11-038 et al.

6. The specific per-kWh DWR Bond Charge component of the DA CRS shall be calculated and implemented in a separate order in A.00-11-038 et al. as part of the implementation of Bond Charges for bundled customers.

7. The Bond Charge shall take effect for designated DA customers under the same schedule and on the same basis as is adopted and implemented for bundled customers pursuant to a separate order in A.00-11-038 et al.

8. The DWR Power Charge component of the DA CRS for the historic period September 21, 2001 through December 31, 2002 shall be determined by performing a DA in/out computer model run, in accordance with the methodology adopted in this order, and consistent with the inter-utility allocations adopted for the historic period in D.02-02-052 adjusted for any true ups to adjust for recorded cost and operational data covering that period, as shall be implemented in connection with the 2003 DWR revenue requirement in A.00-11-038 et al.

9. Interest charges shall accrue on the unpaid balance due under the DWR Power Charge component of the DA CRS for the historic period September 21, 2001 through December 31, 2002, covering the period from September 21, 2001 until bundled ratepayers have been fully reimbursed for all applicable charges of principal plus interest due from DA customers.

10. The DWR interest rate used for accruing under or overcollections during the applicable period shall be used for computing interest credits due from DA customers to bundled customers.

11. The DWR Power Charge component of the DA CRS for the prospective 12 months beginning January 1, 2003 shall be determined by performing a DA in/out computer model run in accordance with the methodology adopted in this order, and consistent with the inter-utility allocations and operational cost assumptions underlying the 2003 DWR revenue requirement that shall be adopted in a separate order in A.00-11-038 et al.

12. The DWR Power Charge component of the DA CRS for the prospective 12 months beginning January 1, 2003 shall be implemented concurrently with DWR 2003 power charges applicable to bundled customers as shall be determined in A.00-11-038 et al.

13. The DWR Power Charge component of the DA CRS shall apply only to those customers that switched from bundled to DA service after July 1, 2001. Customers that were switched to DA prior to July 1, 2001 shall be excluded from the DWR Power Charge component of DA CRS.

14. For purposes of determining a customer's DA or bundled status as of July 1, 2001 for purposes of paying the DWR Power Charge, the customer's billing records shall be used, and not contract execution date.

15. The DWR Power Charge component of the DA CRS shall only apply to that percentage of the DA customer consumption that corresponds to the percentage of the total procurement portfolio supplied by DWR power for the applicable time period.

16. All DA customers, irrespective of the date they began to take DA service shall be required to pay the URG-related component of the DA CRS.

17. For purposes of determining the URG component of the DA CRS for 2003, each utility shall apply the market proxy value for a gas-fired combined cycle unit, as adopted in this order to compute the above-market portion of URG.

18. A preliminary listing of the major categories data inputs and calculations necessary to perform the DA in/out model runs on a total portfolio basis is set forth in Appendix F of this order.

19. The assigned ALJ shall issue a procedural ruling setting a schedule for necessary workshops and compliance filings necessary to compile necessary data inputs, perform revised computer model runs and compute the applicable DA CRS components both for the historic period (i.e., September 20, 2001 through December 31, 2002) and the 12-month prospective period beginning January 1, 2003 to be coordinated, as appropriate with A.00-11-038 et al. proceedings.

20. The ALJ shall issue any additional procedural rulings, as warranted, to develop a further record on the outstanding issues identified in this order, including the issue of appropriate methodologies for performing backcasts.

21. The utilities shall be required to file compliance tariffs necessary to implement the DA CRS provisions adopted in this order following conclusion of the implementation workshops ordered herein and the calculation of the specific DA CRS elements to be implemented in accordance with this order.

22. TURN's recommendation to the costs of the WAPA contract in the DA CRS calculation is hereby adopted.

23. TURN's recommendation to move the costs of interruptible rate discount programs for PG&E and SCE to the distribution rate component is hereby adopted. The ALJ shall issue a ruling concerning the timing of implementation of this measure.

24. The top-100-hour allocation method adopted in D.00-06-034 shall be used for purposes of revenue allocation of the URG component of DA CRS using the factors presented in the utilities' testimony.

This order is effective today.

Dated ____________________________, at San Francisco, California.

Appendixes A-F Wood Comment Dec.