R. 02-01-011

Final Report of the Working Group to Calculate CRS Obligations Associated with Municipal Departing Load and Direct Access

CORRECTED
BY
ENERGY DIVISION

February 1, 2006

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Section I

SUMMARY AND RECOMMENDATIONS

This report presents the conclusions of a Working Group established by several Rulings of ALJ Thomas Pulsifer in Rulemaking R.02-11-011, "Regarding the Implementation of the Suspension of Direct Access Pursuant to Assembly Bill 1X and Decision 01-09-060". The rulings directed preparation of calculations necessary for the billing and collection of the Municipal Departing Load (MDL) Cost Responsibility Surcharge (CRS), and ongoing administration of the Direct Access (DA) CRS.

ALJ Pulsifer assigned 3 specific tasks to the working group:

1. produce the calculations required for the Commission to adopt the Municipal Departing Load (MDL) CRS obligations to date;
2. produce Direct Access (DA) CRS calculations for 2003-2005; and
3. update forecasts of DA CRS and DL CRS obligations through the year 2011, in order to assess whether to revise the currently-in-effect DA CRS cap of 2.7 cents/kWh.

The Working Group met many times and shared the work of developing estimates and writing this report among its members. Except where noted in this report, the group reached consensus on its recommendations.[1] The results and recommendations of the working group are summarized below, grouped according to the tasks assigned by ALJ Pulsifer.

Results of Working Group in Response to ALJ Pulsifer's March 28, 2005 Ruling

This ruling established a working group to produce the calculations required for the Commission to adopt the MDL CRS obligations to date.

[1] Merced Irrigation District and Modesto Irrigation District take no position regarding any portion of this Report that addresses calculation of the Competition Transition Charge (CTC) or anything related to calculation of CTC. On November 23, 2005, Merced Irrigation District and Modesto Irrigation District filed a Petition for Writ of Review of Commission Decision Nos. 05-01-031, 05-02-040, 5-10-046, and 05-10-047 in the California Court of Appeal, Fifth Appellate District (No. F049265) (Petition). Merced Irrigation District and Modesto Irrigation District cannot and will not make any statement or take any position with respect to this Report that might later be taken as contrary to any position taken or argument presented in that Petition. Merced Irrigation District and Modesto Irrigation District expressly disclaim any intent to take any such position in this Report, and hereby reserve all rights in that regard.

The interested parties have been working together to calculate the MDL CRS obligation on a year-by-year basis for the 2003-2005 time period.

It is the DL participant's position that the particular changes in benchmark and methodology that they recommend in this report should form the basis to calculate the DL CRS obligations from 2003 forward. Similarly, it is the IOU participants' position that the particular changes in benchmark and methodology they recommend in this report should also form the basis to calculate the CRS obligations from 2003 forward. This report provides alternative tables utilizing different recommendations for the benchmark and methodology to be employed to calculate the 2003 through 2011 DL CRS obligations.

The working group has completed all tasks that it has identified as within active parties' ability to address in order for the Commission to take action and make the decisions necessary for billing and collection to begin. Once final values are adopted by the Commission and the Commission has approved the investor-owned utilities' advice letter filings (or agreements between an investor-owned utility and a publicly owned utility), billing and collection of MDL CRS can begin.[2]

ALJ Pulsifer's March 28th Ruling also discussed protocols for administering the first-come, first-served rules for POUs seeking to qualify for authorized CRS exclusions. Thus, these protocols were developed and are discussed in Section IV of this report.

Result of Working Group in Response to ALJ Pulsifer's March 30, 2005 Ruling

This ruling directed the Working Group established in the March 28th ruling to produce the CRS calculations for 2003 (on a true-up basis), and for 2004 and 2005 (on a forecast basis), and specifically requested end of year (EOY) DA CRS undercollection balances for each utility for each of these three years. We note that this issue affects DA customers directly, as the application of the 2.7 cent CRS cap, in combination with the delay in the development of the CRS until early 2003, gave rise to an undercollection balance for each utility.

The process of developing EOY undercollection balances for PG&E and Edison necessarily involved the full discussion of the appropriate methodology for determination of the indifference fee, which is fully discussed in Section II-A of this Report. Further, the task of developing EOY undercollection balances involved the further question of whether and to what degree any changes in methodology should be applied to the years

[2] A December 23, 2004 Ruling of the Presiding Administrative Law Judge initiated the process to implement billing and collection relating to cost responsibility surcharges for MDL. Three issues were identified for resolution: (1) identifying customers and measuring usage for MDL CRS; (2) administration of the Commission authorized CRS exemptions; and (3) the need for and level of a MDL CRS cents per Kwh cap. The second of these issues is addressed in this report, while the third does not appear to remain an issue. The first issue, now that this report has resolved calculation issues, may be addressed in the pending advice letters that the IOUs have submitted (or will submit) regarding billing of DL customers.

2003, 2004 and 2005. (With regard to SDG&E, it was clear that the undercollection balance had been paid off in 2005 under the existing methodology, and there was no need for further discussion of the application of methodological changes to the 2003-2005 period.) While the parties were able to reach a consensus view of the appropriate methodology for prospective application, as is discussed fully in Sections II-A and III, their views differed with respect to application of the revised methodology to these earlier periods.

The parties directly interested in the question of DA CRS EOY undercollection balances for PG&E and SCE include those two utilities as well as AReM, CLECA, CMTA, TURN, and ORA. We will refer to these parties herein as the "DA Agreement Parties." The DA Agreement Parties discussed the matter of EOY undercollection balances on numerous occasions. Their discussions involved the extent to which the changes in the methodology agreed upon for prospective application in 2006 and subsequent years should also be applied to the 2003-2005 period. A more detailed description of this discussion and of the ultimate agreement among the DA Agreement Parties is set forth in Appendix E, entitled *DA CRS Undercollection Determinations and Related Implementation Procedures,* which is attached to this Report.

The DA Agreement Parties have agreed that the appropriate level of EOY 2005 DA CRS undercollection for PG&E is $30 million, and that there also exists an undercollection balance associated with the DWR bond charge of $30 million, for a total of $60 million EOY 2005. The DA Agreement Parties have agreed that, at the collection rates that will be experienced in 2006, this undercollection balance will drop to zero on June 30, 2006. The DA Agreement Parties have agreed that the appropriate level of EOY 2005 DA CRS undercollection for SCE is $522 million and that there exists a DWR bond charge undercollection of an additional $55 million, for a total undercollection balance of $577 million EOY 2005. The DA Agreement Parties anticipate that, at expected accrual and collection rates, this undercollection balance will reach zero by the end of 2008. After fixing the end of year 2005 balance, no interim balances prior to that date are needed in order to determine when the loan from bundled to direct access customers will be repaid.

The DA Agreement Parties also reached an agreement on a modified methodology to be used to calculate the ongoing CTC and DWR power charge components of the DA CRS after 2005 and a negotiated agreement on specific market benchmarks for DA CRS calculations for the year 2006. This is fully explained in Sections II-A and III of this Report. The DA Agreement Parties recommend that they be directed to reconvene in August 2006 to refine the methodology for the capacity/resource adequacy adder component of the market-price benchmark for application in 2007 and beyond.

All parties agree that the CRS undercollection for SDG&E was paid off during 2005, and that calculations of the CRS undercollection for SDG&E, through 2005, uses the currently adopted (DWR) methodology based on spot (i.e. less than 90 days) prices and

sales as the market price benchmark, with lagged true-ups for DWR and URG costs. SDG&E filed Advice Letter 1726-E-A to set the DA CRS power charge component to zero, effective November 15, 2005, and since the historical undercollection was paid off prior to the November 15 date, an overcollection amount exists that SDG&E will credit from bundled to DA Non-Exempt customers through a separate advice letter filing, pending a final decision from the Commission in the instant proceeding.

Results of the Working Group in response to ALJ Pulsifer's June 2, 2005 ruling

The June 2, 2005 ruling authorized the Working Group established in the March 2005 Rulings to expand its scope to include modeling work to update forecasts of CRS obligations through the year 2011. One of the purposes of this effort was to assess whether to revise the Direct Access Cost Responsibility Surcharge (DA CRS) cap of 2.7 cents/kWh pursuant to the directives in Decision (D.) 03-07-030.

This report provides the Working Group's calculations of forecasted CRS obligations through 2011 for both DA and DL, subject to or depending upon the Commission's adoption of various recommendations. See Section V, Tables and Section VI, Table 1. Based on the estimates it has developed, the Working Group recommends that the DA CRS cap remain unchanged at the current level, 2.7 cents/kWh.

Other Recommendations By The DA Agreement Parties

In the course of its meetings, the working group also developed the following recommendations associated with DA customers who are not exempt from the DWR power charge, which are necessary to implement its results.

> **CONSENSUS RECOMMENDATION DA #1: Modify the current methodology for the calculation of the Indifference Rate for those DA customers responsible for the DWR power charge to one that compares each utility's total power portfolio costs, expressed in cents/kWh, to a market benchmark comprised of the posted forward prices for a one-year strip of power for the coming year plus a capacity/resource adequacy adder.** This modified market benchmark will allow the Indifference calculation to better reflect the cost impact on the resource portfolio serving bundled customers if the DA load were to return to bundled service. This new approach is mathematically equivalent to the current Indifference calculation, as long as the same benchmark is used to calculate the statutory CTC, as described in Section III. The modified methodology will make the *calculation* simpler, more transparent and less cumbersome than the existing approach. However, in order to achieve this result, the DA Agreement Parties urge the Commission to use a consistent, benchmark, to calculate the statutory CTC in future years. The calculations undertaken using this methodology will reflect the fact that because the calculation of the IOU CTC

is performed based on forecast costs, under- or over-collections in utility ERRA accounts attributable to the cost of resources reflected in the "statutory CTC" calculations as well as other costs of "old world URG" at the end of each year should be reflected in the calculation of the DWR power charge and ongoing CTC components of the DA CRS in the following year. The DWR revenue requirement allocations to the IOUs already include the cost true-ups from prior years, so no explicit adjustment is necessary.

CONSENSUS RECOMMENDATION DA #2: Calculate the DWR Power Charge Component of DA CRS Calculation to Accommodate Both Statutory CTC and the Indifference Standard

The DA Agreement Parties agree that the Commission should determine a consistent methodology for all three IOUs for calculation of the statutory CTC. In order to comply with D. 05-12-045 (whose adoption of the use of the statutory CTC for DA customers was extended to SCE by D. 06-01-035 on January 26, 2006 and may be extended to SDG&E), and to meet the Commission's Indifference standard as adopted in D.02-11-022 et al, the DA Agreement Parties recommend that the DWR Power Charge component of the DA CRS for non-exempt DA customers be replaced with a Power Charge Indifference Adjustment (PCIA), which is to be established such that the sum of the PCIA and the statutory CTC components of the DA CRS equals the Indifference Rate.

CONSENSUS RECOMMENDATION DA #3: Procedures for Implementing Recommendations

Procedurally, each utility should be directed to file an advice letter or augment an advice letter at the end of each year or an update to its ERRA filing to establish the Indifference Rate for the subsequent year, as well as the DWR Power Charge and the CTC rate components of the DA CRS. This filing would be based on cost information contained in the DWR Revenue Requirement proceeding (presently Application 00-11-038 et al.) and the utilities' ERRA proceedings, and subject to the recommendations included in Section III. More detail is provided in Appendix E.

CONSENSUS RECOMMENDATION DA #4: Negative Indifference Rate/PCIA

The DA Agreement Parties agree that the statutory CTC component of the CRS could be larger than the Indifference Rate, and that this will appropriately result in a negative PCIA component of the DA CRS. They also agree that there is some possibility of a negative Indifference Rate. For SCE non-exempt DA customers, given that SCE has a much larger DA CRS undercollection than the other utilities, the DA Agreement Parties agree that if a negative Indifference Rate should occur for SCE, it should be used as a credit against any existing DA CRS undercollections. This concept is consistent with D.05-12-045, which permits a

negative statutory CTC to offset a subsequent positive statutory CTC. Because the DA Agreement Parties agree that the CRS undercollection on the PG&E system will be paid off as of June 30, 2006, the DA Agreement Parties agree that the Indifference Rate for PG&E should not go below zero and that no negative balance will be carried forward for PG&E. This principle of a non-negative Indifference Rate for non-exempt DA customers will also apply to SCE after its DA CRS undercollection has been recovered. The principle of a non-negative indifference rate for non-exempt DA customers is applicable to SDG&E and is consistent with the historical undercollection for SDG&E being paid off in 2005.

CONSENSUS RECOMMENDATION DA #5: Annual Calculation of the Market Price Benchmark

The Working Group recommends that the benchmark for each year be calculated based on an average of one-year strip power futures quotes for NP 15 and SP 15 for the coming calendar year from *Megawatt Daily* published from October 1 through October 31 of the prior year, plus a capacity/resource adequacy adder. [3] Separate benchmarks are to be calculated for PG&E, SCE and SDG&E, based on the futures market most relevant to each utility (NP15 or SP15) and the regional value of capacity/resource adequacy. These benchmarks are to be grossed up for line losses.

CONSENSUS RECOMMENDATION DA#6: The DA CRS cap should not change.

In D.02-11-022 and D.03-07-030, the Commission set a CRS cap for DA load of 2.7 cents per kWh. Based on the most recent data available, there is no need to increase the CRS cap and, therefore, the Working Group recommends that the cap remain at the current level.

Other Recommendations by The DL Parties

It is the Energy Division's understanding that the active DL parties, the group that submitted final edits of this report to the Energy Division, are Merced Irrigation District, Modesto Irrigation District, South San Joaquin Irrigation District, California Municipal Utilities Association, Northern California Power Authority, City of Corona, and City of Rancho Cucamonga.

With the following modifications, the DL parties support all of the Consensus Recommendations put forth by the DA Agreement Parties as applied to DL loads, and believe that these recommendations move the CRS methodology closer to the goal of establishing CRS charges that ensure indifference for bundled customers.

[3] For 2006 only, futures values from November 15th – December 15th were used.

The IOUs generally disagree with the DL Parties' recommendations, insofar as they are inconsistent with the recommendations or underlying rationale for the methodologies set forth above in connection with the DA CRS.

DL Parties Recommendation: Total Portfolio Adjustment

For those DL customers who are exempt from the power charge, apply a "Total Portfolio Adjustment" to account for IOU portfolio costs not included in the Statutory CTC calculation for DL load. [4] This adjustment would be made by allocating the above or below market cost of the residual IOU portfolio [Total IOU portfolio less the Statutory CTC portfolio] pro-rata among non-exempt bundled, DA, and DL customers by volume. Above or below market costs would be calculated in reference to the market price benchmark established in this proceeding (See DL Recommendation #1 in Section 3). For the years 2004, 2005 and 2006, the Total Portfolio Adjustment would be as set forth in Table Appendix C-1, in Appendix C, as shown for the DL recommended methodology and benchmark.[5] For 2007 forward, the Total Portfolio Adjustment would be determined in the ERRA proceeding and would be applied to non-bundled customers exempt from the DWR Power Charge and subject to CTC. Projected results based on various alternative benchmarks and methodologies are shown in the same table.

IOUs' Position On DL Parties Recommendation re Total Portfolio Adjustment:

There should be no "Total Portfolio Adjustment" for any customers, DA or DL, who are exempt from responsibility for DWR power charges. The IOUs believe that such an adjustment is simply a two-step approach to calculating the ongoing CTC on a "total portfolio" basis, rather than the statutory basis adopted for all customers in PG&E's 2006 ERRA forecast decision, D. 05-12-045. The IOUs believe that the DWR power charge component of the CRS should be calculated the same for all non-bundled customers who are responsible for such charge and using the approach outlined in Consensus Recommendations DA #1 - #4. The IOU's believe that the ongoing CTC component of the CRS should be calculated for all customers who are obligated to pay CTC pursuant to the methods adopted in each IOU's ERRA proceeding.

DL Parties Recommendation: Negative Indifference Rate/DWR Power Charge

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4 See computational example in Appendix 1C.

5 The Total Portfolio Adjustment would not apply for year 2003 as, in accordance with Commission Decision 05-01-040, issued in this Rulemaking proceeding in January 2006, the CTC rate for 2003 has been set at $0.00.

In those instances in which the DWR Power Charge is negative and to the extent that it offsets the Statutory CTC in its entirety, the DL participants believe that the Indifference Rate should be allowed to go negative. Once the negative Indifference Rate has been applied to recover past undercollections, then it should be applied to offset other components of the CRS. Consistent with the treatment of CTC in Decision 05-12-045, in any month in which a negative Indifference Rate is not used to offset past undercollections or other components of the CRS charge, then it should be carried forward in order to offset future CRS charges. The DL participants in the Working Group believe that such offsets must occur in order to maintain the overall goal of bundled customer indifference.

IOUs' Position On DL Parties Recommendation re: Negative Indifference Rate/DWR Power Charge

The IOUs' believe that the possibility of a negative DWR power charge as a result should be addressed as described in Consensus Recommendation DA# 4 for all customers who are responsible for DWR power charges. Specifically, the Indifference Rate should be non-negative for each IOU after that IOU's existing DA CRS undercollection is eliminated. The IOUs believe that allowing the Indifference Rate to go negative after the existing DA CRS undercollection is eliminated is effectively paying DA and DL customers for departing from, or for having departed from, the IOUs' procurement activities.

Organization of this Report

In order to develop the numerical results requested by ALJ Pulsifer, the Working Group revisited and reconsidered the existing methodology that the Commission relies upon for these calculations, as well as the market price benchmark that is perhaps the most critical component used in these calculations. Thus, this report begins by discussing and recommending revised methodologies for calculating the DA and DL CRS in Section II, followed in Section III by a discussion and recommendation for a revised method for developing a more appropriate market price benchmark.

Section IV discusses other data required for the DA and DL CRS estimates, and provides procedural recommendations as to which Commission proceedings should be the "home" for these calculations.

With all the methodological, data, and procedural update issues resolved, Section V provides the numerical results derived from the utilization of the alternative recommendations of the Working Group participants, based on data inputs provided by the IOUs and DWR, and modeling provided by Navigant. The projections of CRS going forward are necessarily illustrative as final CRS determinations will be made pursuant to future Commission rulings. As noted in this report, in some cases, the Working Group participants have not reached consensus on the appropriate cost components and loads to be included in the calculations, and in those cases, the results shown in this Report are preliminary. These preliminary results will be recalculated and finalized once the Commission issues a decision on any disputed items identified in this report.

Finally, the numerical results form the basis for Section VI, which discusses estimates of when the DA CRS undercollection will be paid off and explains why these estimates support the Working Group's recommendations that the current 2.7 cents per kWh cap be left unchanged.

In drafting this report, Working Group members opted to include considerable detail to support their discussion of the issues they considered. This was included in order to allow the report to stand alone and provide the reader with sufficient information to understand how the Group arrived at its recommendations.

Issues Identified by DL Parties as Requiring Commission Resolution

Energy Division note: Following the final meeting of the Working Group, and as this report was being finalized, the DL Parties added the text in this section to the Working Group report. The Energy Division, which organized and facilitated this Working Group as ordered by ALJ Pulsifer, objected to the inclusion of this text, which could be construed to suggest that the Working Group did not provide a forum for constructive resolution of the issues listed below. In fact, such a forum was provided: the Working Group was organized with this goal clearly stated from the outset.[6] The inclusion of this open-ended list of issues at the request of a group of regular participants in every Working Group meeting over the last 9 months is inconsistent with the basic purpose of establishing the group to begin with: to reach consensus where possible, and to provide a clear choice to the Commission on contested issues. Nevertheless, because the DL parties insist that this text be included, it has been left in the report.

[Beginning of DL Parties' text]

This Workshop Report identifies specific issues to which the Working Group was unable to reach consensus. Resolution of these specific issues is required prior to the final determination of the DL CRS obligation for the period of 2003 through 2006 and both the DA and DL CRS obligation for 2007 forward. Although this Report includes some detail

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6 See Part I of the Energy Division's April 18th, 2005 "Status Report To ALJ Pulsifer on MDL CRS Billing And Collection Bilateral Negotiations and First Meeting of DA/ MDL CRS Calculation Working Group":

"Following introductions and a review of the agenda, the group discussed the suggested working group objectives outlined on the agenda (the complete agenda is attached to the report). No participants disagreed with these objectives, so at least on a working level, the Energy Division considers them as guides for the group's efforts from this point forward:

- *determine what is owed, who owes it to whom, and how it will be collected*
- *finalizing calculations relating to the MDL CRS obligations to date*
- *produce the CRS calculations for 2003 (on a true-up basis), and for 2004 and 2005 (on a forecast basis)"*

No participants in the working group ever contested these objectives in comments on the Status Report.

regarding these unresolved issues, the parties reserve the right to voice further arguments in comments submitted on the Proposed Decision and, if necessary, request additional hearings on these unresolved issues.

These unresolved issues include Commission policies regarding:

1. Determination of appropriate capacity adders to the market price benchmark for 2007 and beyond.
2. Application of the Total Portfolio Adjustment as recommended by the DL parties.
3. Negative components of the CRS, including whether a particular negative CRS component can be used to offset any other components of the CRS (other than CTC); and how the Commission views a negative component of the CRS in the context of bundled customer indifference.
4. Exemption from cost responsibility for utility procurement contracts executed subsequent to a customer's departure from the utility's system.
5. The appropriate cost components and loads to be included in the calculation of each of the components of the CRS.
6. Criteria for identifying New World Resources.
7. Allocation of MDL exemptions.
8. Billing and collections of CRS from MDL.

[End of DL Parties' text]

Section II

RECOMMENDED REVISED CRS CALCULATION METHODOLOGY

This section provides the Working Group's recommended revisions to the currently adopted CRS Calculation Methodology for the DWR Power Charge and CTC components of the CRS. For clarity, Section II-A presents the discussion from the perspective of Direct Access concerns, and Section II-B presents the same discussion, from the perspective of Departing Load concerns.

Section II-A

DIRECT ACCESS

Summary: The Working Group recommends that the Commission modify the current modeling methodology used to calculate the set of rate components for the CRS for non-exempt DA customers for the cost of DWR and "old world" utility power. The choice of modeling methodology plus input assumptions results in EOY accruals and undercollection balances that can be determined through EOY 2005. While the DA Agreement Parties have different preferences for when these modeling changes should begin, they have reached a compromise agreement (attached) on the resulting EOY 2005 undercollection balance for PG&E and SCE. All parties agree that the EOY 2005 undercollection balance for SDG&E is zero.

A. Historical Methodology

In D.02-11-022 the Commission ordered that certain direct access (DA) customers pay a DWR Power Charge and a CTC component of the CRS in an amount that holds bundled customers indifferent to the departure of these DA customers from bundled service. This CRS includes an "Indifference Rate" which insures that the bundled customers' average rate for delivered power does not increase due to the departure of the post-July 1, 2001 DA load from bundled service. The Indifference Rate is equal to the sum of the Ongoing DWR Power Charge and CTC rate components. It is calculated using a "Total Portfolio" approach adopted in D.02-11-022, which looks at the impact of the departing DA load on the cost of the total utility portfolio, i.e. all of the generation resources serving the remaining bundled customers. It applies to non-exempt DA load, i.e. DA load which is not exempt from the Ongoing DWR Power Charge component of the DA CRS.

The Commission's description of the CRS and its calculation in D.02-11-022 are provided in Appendix D.

Historically, for customers in the SCE service territories, the CTC rate component has been calculated in the company's ERRA proceeding using the Total Portfolio approach described by the Commission in D.02-11-022. The Total Portfolio approach includes all

"old world" IOU resources in the above market cost calculation. For customers in PG&E's service territory, the CTC rate component of the CRS has been determined in PG&E's ERRA proceeding pursuant to the provisions of Assembly Bill ("AB") 1890 (the "Statutory Approach"). The Statutory Approach for calculating CTC includes only those "old world" IOU resources identified in Public Utilities Code Section 376(a) in the above market cost calculation. The benchmark used in the calculation of the Statutory CTC calculations has been based on the levelized cost of a combined cycle turbine as the benchmark, whereas the benchmark for the Indifference Rate calculation has been the IOU's weighted average price of spot purchases and surplus sales. SDG&E utilizes the statutory approach for calculating the CTC in SDG&E's 2006 ERRA filing.

Pursuant to D.02-11-022, the DWR Power Charge component of the DA CRS is currently calculated in all three IOU service territories as the difference between the Indifference Rate and the CTC rate component discussed above.[7] The total payment by non-exempt DA customers is subject to a 2.7 cent/kWh cap.

B. Working Group Concerns with Historical Methodology

Some Working Group members have identified several concerns regarding the present CRS modeling methodology:

1. The historical use of spot purchases and surplus sales prices as a market price benchmark for calculating the Indifference Rate may not measure bundled customer indifference accurately, under a variety of market conditions. A more appropriate market price benchmark is recommended in Section III of this report. In addition, Working Group members agree that the recommended market price benchmark should be applied consistently across all relevant CRS charges (CTC and Ongoing DWR Power for DA customers). However, SDG&E is concerned with additional cost shifting to bundled customers should the market price benchmark be used to determine the CTC in SDG&E's 2006 ERRA filing, thus SDG&E recommends that the market price benchmark be applied to the DA CRS calculation for 2006, but not SDG&E's CTC calculation in its 2006 ERRA filing. PG&E's 2006 ongoing CTC has already been set in the 2006 ERRA filing and is not intended to be modified.

2. Under the current methodology, the determination of the Ongoing DWR Power Charge rate component of the CRS cannot be achieved in a timely manner, in part because of the need to true up the DWR and utility costs after the fact. This has left affected parties without information concerning the level of exit fee liability applicable to their current consumption. Further, the current method relies on utility power purchase and sales data which the utilities view as confidential and

[7] See computational example in Appendix 1A. This example was prepared by DL parties. No other Working Group participants have disputed its accuracy.

proprietary. Thus, important cost data are not made available to many of the parties that will be held responsible for paying the exit fees. The DA Agreement Parties all agree that the methodology should be revised so that customers can know their exit fee liability on a current basis.

C. Working Group Consensus DA Recommendations

All Working Group members recommend that the Commission adopt the following methodological changes to calculate the DWR Power Charge and CTC components of the DA CRS for their DA customers who are not exempt from the DWR Power Charge:

CONSENSUS RECOMMENDATION DA #1: Change the current methodology for calculation of the Indifference Rate for those DA customers responsible the DWR power charge to one that compares each utility's total power portfolio costs, expressed in cents/kWh, to a market price benchmark comprised of the cost of a one-year strip of power plus a capacity/resource adequacy adder.

This new approach will be simpler, more transparent and less cumbersome than the existing approach. Use the same, consistent, benchmark, as described more fully in Section III, to calculate the statutory CTC, with the exception of 2006 for SDG&E and PG&E where the CTC calculation shall employ the benchmark based upon the Market Price Reference model as set forth in SDG&E's and PG&E's 2006 ERRA filings. The calculations undertaken using this methodology will reflect the fact that because the calculation of the IOU CTC is performed based on forecast costs, under- or over-collections in utility ERRA accounts attributable to the cost of resources reflected in the "statutory CTC" calculations as well as other costs of "old world URG" at the end of each year[8] should be reflected in the calculation of the DWR power charge and ongoing CTC components of the DA CRS in the following year. The DWR revenue requirement allocations to the IOUs already includes the cost true-ups from prior years, so no explicit adjustment treatment is necessary.

CONSENSUS RECOMMENDATION DA #2: Replace the DWR Power Charge Component of the DA CRS With a Power Charge Indifference Adjustment to Accommodate Statutory CTC and the Indifference Standard.

The DA Agreement Parties agree that the Commission should determine a consistent methodology for each IOU for calculation of the ongoing CTC. In order to comply with D.05-12-045 (whose adoption of the use of the statutory CTC may be extended to SCE and SDG&E), and to meet the Commission's

[8] If the decision in an IOU's General Rate Case or similar base revenue requirement proceeding changes that utility's generation revenue requirement by more than 2% in mid-year, the utility shall file an advice letter to update the DA CRS to reflect that change in generation base revenue requirement. This adjustment is necessary because generation base revenue requirements are not trued up to actual costs in the same manner as ERRA and DWR costs.

Indifference standard as adopted in D.02-11-022 et al, the DA Agreement Parties recommend that the DWR Power Charge component of the DA CRS for non-exempt DA customers be replaced with a Power Charge Indifference Adjustment (PCIA) set such that the sum of the PCIA component of the DA CRS and the statutory CTC component equals the Indifference Rate, which is to be calculated using a consistent market price benchmark with that used for the statutory CTC component. SDG&E's 2006 ERRA filing employs the statutory method for calculating the CTC, and as stated previously, in order to prevent undue cost shifting to bundled customers, SDG&E's CTC calculation in its 2006 ERRA filing shall not be subject to the market benchmark from the DA CRS Working Group.

CONSENSUS RECOMMENDATION DA #3: Procedures for Implementing Recommendations.

Procedurally, each utility should be directed to file an advice letter or augment an advice letter at the end of each year or to file an update to its ERRA filing to establish the Indifference Rate for the subsequent year, as well as the PCIA and CTC rate components of the DA CRS. This filing would be based on cost information contained in the DWR Revenue Requirement proceeding (presently A.00-11-038 et al.) and the utilities' ERRA proceedings, and subject to the recommendations included in Section III. More detail is provided in Appendix E.

CONSENSUS RECOMMENDATION DA #4: Negative Indifference Rate/PCIA.

The DA Agreement Parties agree that the statutory CTC component of the CRS could be larger than the Indifference Rate, and that this will appropriately result in a negative DWR Power Charge component of the DA CRS. They also agree that there is some possibility of a negative Indifference Rate. For SCE non-exempt DA customers, given that SCE has a much larger CRS undercollection than the other utilities, the DA Agreement Parties agree that a negative Indifference Rate, should one occur for SCE, should be used to offset any existing DA CRS undercollection for the customer. This concept is consistent with D.05-12-045, which permits a negative statutory CTC to offset a subsequent positive statutory CTC. The DA Agreement Parties agree that once the existing CRS undercollection is eliminated, the Indifference Rate for non-exempt DA customers will be non-negative, and that no negative balance will be carried forward.

D. Implementation of Recommendations

The DA Agreement Parties recommend that these proposed changes to the CRS Methodology, and the proposed new market price benchmark recommended in Section 3, be implemented prospectively, beginning in 2007. All matters related to the CRS for

non-exempt DA customers through 2006 have been resolved through negotiation and are Appendix E, which adopts EOY undercollection balances for the year 2005 and proposals for addressing the DA CRS for 2006.

SECTION II-B

DISCUSSION OF DEPARTING LOAD (DL) METHODOLOGY

Summary: The Working Group recommends that the Commission modify the historical modeling methodology used to calculate the set of rate components for the CRS for non-bundled departing load customers for the cost of DWR and utility power. Some parties believe that these modifications should only begin in the year 2007. Other participants believe that they should be made applicable to the calculation of the Departing Load (DL) CRS for the period 2003-2006, as well. Parties are in the process of trying to settle the 2003 through 2006 charges.

Energy Division Note: Issues related to Departing Load turned out to be the most challenging for the Working Group. For this reason, the members of the group decided to format this section by first presenting a discussion of the issues by the DL parties, and following that discussion with the IOUs' perspective on the same issues. The purpose of this approach is to clearly identify issues that require a Commission decision to resolve.

Discussion By DL Parties

A. Historical Methodology for Calculation of DL CRS

Prior Commission decisions ordered that certain departing load customers pay a CRS that holds bundled customers indifferent to the departure of these loads from bundled service. This CRS includes an "Indifference Fee" which insures that the bundled customers' average rate for delivered power does not change due to the departure of load from bundled service. The Indifference Fee is equal to the sum of the Ongoing DWR Power Charge and CTC rate components. It is calculated using a "Total Portfolio" approach adopted in Decision No. 02-11-022, which looks at the impact of the departing load on the cost of the total utility portfolio, i.e., all of the generation resources serving the remaining bundled customers. This total portfolio approach was extended to municipal DL in D.03-07-028.[9] The Indifference Fee benchmark has historically applied a market price benchmark based upon the weighted average price of spot purchases and surplus sales. The DWR Power Charge Accrual is calculated as the difference between the Indifference Fee and the CTC rate component discussed below.[10]

For customers in PG&E's service territory, the CTC rate component of the CRS is determined in PG&E's ERRA proceeding pursuant to the provisions of Assembly Bill

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[9] D.03-07-028, at 79, Ordering Paragraph 10 ("The MDL CRS shall be determined in accordance with the DA-in/out methodology on a total portfolio basis, as adopted for DA customers in D.02-11-022.").

[10] See computational example in Appendix 1A. This example was prepared by DL parties. No other Working Group participants have disputed its accuracy.

1890 (the "Statutory Approach"). The Statutory Approach for calculating CTC, which was recently confirmed in Decision 05-12-045,[11] excludes certain IOU resources in the above market cost calculation and applies a market price benchmark based upon the levelized cost of a combined cycle turbine. For customers in SCE's service territory, the CTC component of the CRS is calculated in its ERRA proceeding using the Total Portfolio approach described in Decision 02-11-022. The Total Portfolio approach includes all IOU resource costs in the above market cost calculation. However, on December 22, 2005, in accord with a December 20, 2005 Administrative Law Judge's Ruling in its ERRA proceeding (A. 05-08-002), SCE submitted revised CTC calculations consistent with D. 05-12-045 (i.e., derived using the Statutory Method). SDG&E utilizes the statutory approach for calculating the CTC in SDG&E's 2006 ERRA filing.

A number of Commission Decisions address MDL CRS, and establish limited exemptions from certain components of the MDL CRS. (See Commission Decisions 03-07-028, 03-08-076, 04-11-014, 04-12-059, 05-07-038, and 05-08-035..) The cost allocation for MDL CRS calculations are customer specific and depend on the data inputs for that year. MDL customers are responsible for different amounts of past DL CRS obligations based upon their year of departure.

The investor-owned utilities (IOUs) are collecting CRS from a limited number of Departing Load customers. The Commission is currently addressing MDL CRS billing and collection issues through this Working Group and, potentially, the advice letter process, beginning with PG&E's currently-suspended Advice Letters 2433-E-C and 2483-E-A.

B. DL Parties Concerns with Current Methodology

The DL Parties have identified several concerns regarding the present DL CRS modeling methodology:

1. The historical use of spot purchases and surplus sales as a market price benchmark does not measure bundled customer indifference. A more appropriate market price benchmark is recommended in Section III of this report. In addition, Working Group members agree that the recommended market price benchmark should be applied consistently across all relevant DL CRS charges, including CTC as determined in ERRA.

2. Departing Customers who pay the Statutory CTC rate component of the CRS but not the DWR Power Charge rate component of the CRS assert that they are not treated equivalently with other departing customers with respect to the IOUs' portfolio costs. For departing customers that pay both charges, all IOU portfolio costs to serve bundled customers are included in the CRS "Indifference Fee" calculation. For customers that pay the Statutory CTC but not the DWR Power

[11] *See* Footnote 1 (referencing the appeal of Modesto and Merced Irrigation Districts of the Commission's authorization of the use of the Statutory Method for the calculation of CTC)

Charge there is no "Indifference Fee" calculation applied. DL Parties believe that the resulting CRS is inconsistent with the adopted Total Portfolio methodology.

3. Under the historical methodology, the determination of the Ongoing DWR Power Charge rate component of the CRS cannot be achieved in a timely manner, in part because of the need to true up the DWR and utility costs after the fact. This has left affected parties without information concerning the level of exit fee liability applicable to their current consumption. Further, the historical method relies on utility power purchase and sales data which the utilities view as confidential and proprietary. Thus, important cost data are not made available to many of the parties that will be held responsible for paying the exit fees.

C. DL Parties' Recommendations for the Calculation of DL

The DL Parties recommend that the Commission adopt the following methodological changes to calculate the DL CRS:

RECOMMENDATION DL #1: Apply the recommended market price benchmark (comprised of the cost of a one-year strip of power plus a capacity/resource adequacy adder) as described in Section III, to calculate the DL CRS. In this respect the DL Parties adopt the following procedures set forth in Section II of Appendix E as being applicable to the calculation of the components of the DL CRS.

- The benchmark power cost for purposes of determining the Indifference Rate and CTC for 2006 should be comprised of the average of cost quotes for one-year strips of power taken during the period November 15 through December 15 and a Resource Adequacy / generation capacity ("RA/Capacity") cost adder. For years following 2006, the benchmark for each year will be utilized to calculate both the Indifference Rate and CTC, and shall be calculated based on an average of one-year strip power futures quotes for NP 15 and SP 15 for the coming calendar year from *Megawatt Daily* published from October 1 through October 31 of the prior year, plus a capacity/resource adequacy adder. The power costs will be differentiated as between NP 15 and SP 15, and applied to PG&E and SCE accordingly. These benchmarks will be grossed up for line losses. The power costs reflect a 6 X 16 product and the price will be multiplied by a factor of 0.87 to convert the power cost to a 7 X 24 product price.
- For 2006, the parties agree that the RA/Capacity cost adder will be $8/MWH for SCE and $4/MWH for PG&E, which will be added to the average strip price. The parties agree that they will revisit the level of the RA/Capacity cost adders for years after 2006 as more information concerning the cost of generation capacity and/or resource adequacy becomes available.

- For PG&E, the new market benchmark for 2006 will be $90.12/MWH. For SCE, the new market benchmark for 2006 will be $95.17/MWH.[12]

RECOMMENDATION DL #2: Calculate the DWR Power Charge Component of the DL CRS to accommodate Statutory CTC and the Indifference Rate for those DL customers who pay the DL Power Charge. In this regard, the DL Parties adopt the following procedures set forth in Section II of Appendix E as being applicable to the calculation of the CRS for DL which pay the Power Charge:

- The revised benchmark power cost will be compared to the average cost of the utilities' total portfolio, including both URG power and their allocated DWR power costs, to determine the level of the Indifference Rate for that year.[13] The utilities shall file an advice letter prior to the end of the year or update their testimony in their ERRA proceedings to reflect such Indifference Rate in the CRS adopted for the subsequent year.
- The CTC figure adopted in PG&E's ERRA proceeding will be used in conjunction with the Indifference Rate calculation such that the DWR Power Charge component of DA CRS for DA customers not exempt from that charge will be the residual of the Indifference Rate less the CTC. DL Parties further believe that the DWR Power Charge component of DL CRS may be a negative number in those instances in which the CTC is larger than the Indifference Rate, so that overall indifference is maintained. The DL Parties also believe that to the extent that the overall Indifference Rate is a negative number it should offset any past CRS undercollections.
- Now that the statutory approach to CTC calculation is also adopted for SCE in D. 06-01-035, that such CTC figure for SCE will be used in the Indifference Rate calculation in the same manner delineated above for PG&E above.

To address certain of their remaining concerns, and to ensure that bundled customers are held indifferent to the departure of departing load, the DL Parties advance the following additional recommendations:

DL RECOMMENDATION # 3: For those DL customers who are exempt from the power charge, apply a "Total Portfolio Adjustment" to account for IOU

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12 These benchmarks represent the 30-day average, over the period from November 15, 2005 to December 15, 2005, of 12 month forward prices for 2006 at NP 15 and SP15, respectively, to which is added a "resource adequacy" amount of $4/MWH for PG&E and $8/MWH for SCE.

13 See computation example in Appendix 1B.

portfolio costs not included in the Statutory CTC calculation for DL load.[14] This adjustment would be made by allocating the above or below market cost of the residual IOU portfolio [Total IOU portfolio less the Statutory CTC portfolio] pro-rata among non-exempt bundled, DA, and DL customers by volume. Above or below market costs would be calculated in reference to the market price benchmark established in this proceeding (See DL Recommendation #1). For the years 2004, 2005 and 2006, the Total Portfolio Adjustment would be as set forth in Table Appendix C-1, in Appendix C, as shown for the DL recommended methodology and benchmark.[15] For 2007 forward, the Total Portfolio Adjustment would be determined in the ERRA proceeding and would be applied to non-bundled customers exempt from the DWR Power Charge and subject to CTC. Projected results based on various alternative benchmarks and methodologies are shown in the same table.

DL customers believe that this Total Portfolio Adjustment is necessary to ensure equivalent treatment of DA and DL customers as well as to hold bundled customers indifferent on a Total Portfolio Basis, to all classes of direct access and departing load.

Absent this recommended total portfolio adjustment, DL customers believe that the current methodology will not ensure bundled customer indifference. Specifically, those migrating customers subject to only to CTC calculated using the Statutory methodology will not receive the benefit of the below market costs of the residual portfolio and, therefore, DL Parties believe, the resulting charges will continue to be inconsistent with the CPUC-mandated Total Portfolio approach for determining bundled customer indifference (i.e., bundled customers will not be indifferent to the departure of the load, but, in fact, will benefit therefrom).

The DL customers recommend that this issue be set for further process by the Commission.

DL RECOMMENDATION # 4: In those instances in which the DWR Power Charge is negative and to the extent that it offsets the Statutory CTC in its entirety (see discussion in DL Recommendation #2), the DL participants believe that the Indifference Rate should be allowed to go negative. Once the negative Indifference Rate has been applied to recover past undercollections, then it should be applied to offset other components of the CRS. In any month in which a negative Indifference Rate is not used to offset past undercollections or other components of the CRS charge, then it should be carried forward in order to offset

[14] See computational example in Appendix 1C.

[15] The Total Portfolio Adjustment would not apply for year 2003 as, in accordance with Commission Decision 05-01-040, issued in this Rulemaking proceeding in January 2006, the CTC rate for 2003 has been set at $0.00.

future CRS charges. DL Parties believe this is consistent with the treatment of CTC in Decision 05-12-045.

The DL participants in the Working Group believe that such offsets (e.g., negative Indifference Rate offsetting other CRS components) must occur in order to maintain the overall goal of bundled customer indifference. In short, the DL participants in the Working Group believe that the components of the CRS all represent various costs of power commitments made by or on behalf of the IOUs prior to the time of the DL customer's departure. DL Parties believe that in order to ensure that bundled customers do not change from the departure (i.e., are no longer indifferent), the offsets of the various cost components should be allowed to occur.

DL RECOMMENDATION # 5: <u>CRS Credit to Former Bundled Customers for DL Customers</u>

In the January 25, 2005 Administrative Law Judge's Ruling Providing Agenda for Municipal Departing Load Billing and Collection Workshop, ALJ Pulsifer directed parties to address: "How will MDL customers, who have helped finance the DA undercollection as bundled customers, receive a credit against their CRS once they've become an MDL customers?"

The Working Group briefly addressed this issue, discussing whether departing load customers who were bundled customers at a time when bundled customer payments were subsidizing direct access cost responsibility should be entitled to a CRS credit when direct access and departing load customers begin paying this liability. DL Parties believe that because these departing load customers (while still bundled) paid utility and DWR costs on behalf of direct access load, they should be entitled to a pro-rata share of the debt repayment.

In order to determine what, if any, credit would be due to a transferred MDL customer, it is necessary to determine the amount of the undercollection at the time the load departed. For example, the Turlock Irrigation District ("TID"), pursuant to a negotiated agreement with Pacific Gas and Electric Company, assumed a specified number of transferred MDL customers on December 8, 2003. Pursuant to a previous CPUC decision, prior to the transfer those customers paid PG&E bundled service rates. While a rate freeze was in effect at the time the customers were transferred from PG&E to TID, in March 2003, the Commission had approved a three cent rate increase that was paid by all bundled service customers – residential, commercial and industrial. Accordingly, from March 2003 until December 2003, the now TID customers helped to subsidize the CRS undercollection that resulted from the 2.7 cent price cap and must be reimbursed for their contributions.

Logistically, the determination of this credit would involve a one-time determination based on the "vintage" of the Departing Load. Departing Load

customers that were direct access customers during the period when the liability accrued would not be eligible for the credit.

F. Implementation of Recommendations

The DL participants are awaiting the issuance of this report and the revised calculation of the CTC and DWR Power Charge components to initiate, resume, or complete settlement discussions with the IOUs. In the event settlement discussions are unsuccessful, the DL Parties believe that the recommended changes in methodology should be effective from 2003 forward, because the market price benchmark applied in the past does not measure bundled customer indifference and 2002 was the last year that the Commission reviewed the CRS undercollection balances (D. 03-07-030).
[End of Discussion by DL Parties]

<u>Discussion By IOUs</u>

A. Historical Methodology for Calculation of DL CRS

With only one exception, albeit a very important one, the IOUs agree with the description of the calculation of the indifference rate set forth by the DL Parties. The one exception is that the IOUs believe that the indifference rate is a ratemaking mechanism applicable to those non-bundled customers who are responsible for the DWR power charge, and only those non-bundled customers. As the Commission stated in D. 03-07-028, for example:

> "We conclude that MDL customers should be held responsible for a fair share of ongoing DWR power costs in order to avoid cost shifting in compliance with AB 117. We shall therefore impose a component for DWR power costs patterned after the DA CRS which covers the period since September 21, 2001. During this period, DWR has been collecting its revenue requirement through bundled customer proceeds based on power charges that were implemented in D.02-02-052 and DA CRS methodology implemented pursuant to D.02-11-022. MDL customers have not paid anything since their departure to municipal service to cover their share of past costs incurred by DWR during this period. Accordingly, a separate element must be quantified to assess the requisite share of costs on MDL customers covering their responsibility for this period. We discuss further implementation measures in this regard in Section V.C. below" (D. 03-07-028 p. 36; See also *Id*., Ordering Paragraphs 3, 4, and 5 ("The DWR ongoing power charge shall be applicable for above-market DWR power costs incurred beginning September 21, 2001, and continuing until bundled customer indifference has been achieved.").)

Thus, in particular, the IOUs believe that the indifference rate, and by extension a total portfolio approach, is applicable to those customers who are responsible for DWR power costs. If it were applicable to all DL customers, then it would in effect mean that the ongoing CTC for all customers is calculated on a total portfolio basis. The IOUs believe that this would stand in direct contradiction to the statutory method adopted for calculating CTC for all customers in PG&E's and SCE's 2006 ERRA forecast proceedings.

B. Working Group Concerns with Current Methodology

With only one exception, the IOUs do not take issue with the concerns with the current methodology expressed in this section of the DL Parties' analysis. The disagreement is the same as is set forth above. As described above, the IOUs believe that the indifference rate is applicable only to those non-bundled customers who are responsible for DWR power costs. Concern number 2 identified by the DL Parties is that the current method may not apply any indifference rate to those DL customers who pay ongoing CTC but not the DWR power charge. To the extent that this is an accurate description of the current method, the IOUs do not believe that is a cause for concern.

C. DL Recommendations for the Calculation of DL CRS

The IOUs have the following response to the DL Parties recommendations:

> **RECOMMENDATION DL #1:** The IOUs disagree with the DL Parties' recommendation here. The IOUs recommend that the proposal they put forth in connection with the determination of the Indifference Rate and DWR power charge for DA customers be applicable to any DL customers who are responsible for the DWR power charge, as well.
>
> For PG&E, beginning in July of 2006, and for SCE, beginning January of 2006, the Indifference Rate should be used to determine the DWR power charge component of the CRS for these customers. For all customers, the 2006 CTC rate has already been determined in PG&E's and SCE's 2006 forecast ERRA proceeding. This differs from the DL recommendation in that the DL recommendation is to recalculate the 2006 CTC rate.
>
> **RECOMMENDATION DL #2:** The IOUs disagree with the DL Parties' recommendation here. The IOUs recommend that the proposal they put forth in connection with the determination of the Indifference Rate and DWR power charge for DA customers that are responsible for the DWR power charge be applicable to any DL customers who are responsible for the DWR power charge, as well.
>
> In particular, once the DWR power charge and CTC rate components are set on a bottoms up basis, then the Indifference Rate should not be allowed to be negative.

With respect to negative CTC, for PG&E the treatment of negative CTC adopted by the Commission in PG&E's 2006 ERRA forecast proceeding should be as adopted in that proceeding, and not modified as a result of this proceeding.

For SCE, the same approach discussed above for PG&E would apply except that, consistent with its approach to DA customers, SCE would apply any negative Indifference Rate towards past undercollections from DL customers who are responsible for payment of both DWR power charge and CTC components of the CRS.

DL RECOMMENDATION # 3: The IOUs disagree with the DL Parties' recommendation here. The DL Parties argue that the indifference rate should be used to lower DL customers' charges, regardless of whether the DL customers are responsible for DWR power charges. As is explained above, the IOUs believe the indifference rate is applicable only to non-bundled customers who are responsible for the DWR power charge. The IOUs believe that if the "Total Portfolio Adjustment" recommended by the DL Parties is applied to the DL customers who are exempt from the DWR power charge then the result will be that, in effect, the ongoing CTC charged to these customers is the total portfolio CTC, rather than the statutory CTC adopted as applicable to all customers in PG&E's and SCE's 2006 forecast ERRA proceedings.

DL RECOMMENDATION # 4: The IOUs disagree with the DL Parties' recommendation here, as well. The IOUs believe that the possibility of a negative DWR power charge should be addressed as described in Consensus Recommendation DA# 4 for all customers who are responsible for DWR power charges. Specifically, the Indifference Rate should be non-negative for each IOU after that IOU's existing DA CRS undercollection is eliminated. The IOUs believe that allowing the Indifference Rate to go negative after the existing DA CRS undercollection is eliminated is effectively paying DA and DL customers for departing from, or for having departed from, the IOUs' procurement activities. Additionally, use of a negative Indifference Rate to offset other CRS charges such as the DWR bond charge or PG&E's ECRA charge is inappropriate. This argument, were it successful, would also impact the very nature of the consensus benchmark agreement which represented a compromise between the DA Agreement Parties. The IOUs would be far less comfortable with the agreed benchmark if it could lead to payments to certain groups of departed customers.

DL RECOMMENDATION # 5: <u>CRS Credit to Former Bundled Customers for DL Customers</u>

In the January 25, 2005 Administrative Law Judge's Ruling Providing Agenda for Municipal Departing Load Billing and Collection Workshop, ALJ Pulsifer directed parties to address: "How will MDL customers, who have helped finance

the DA undercollection as bundled customers, receive a credit against their CRS once they've become an MDL customers?"

The IOUs believe that issuing a CRS credit to affected direct access and departing load customers is unwarranted, administratively complex and cost prohibitive and should be avoided. Customers who have departed an IOU's system should not be paid to have done so.

Additional IOU Recommendation

The IOUs believe that the Commission has provided clear direction that departing load shall be responsible for non-bypassable charges resulting from any "New World" procurement obligation (IOU procurement activities since January 1, 2003)[16]. Because the calculation of New World cost responsibility depends on when a particular customer departed bundled service, a separate "New World" charge type is recommended. This charge cannot go negative. The New World charge would be calculated in each IOUs' ERRA case, using a consistent benchmark, as described further in Section IV.

F. Implementation of Recommendations

The IOUs believe that unless an agreed-upon resolution of issues is reached with the DL parties, the currently adopted methods should apply through 2005, and the methods adopted as a result of this effort should apply prospectively from when the Commission decision is issued.

[End of Discussion by IOUs]

[16] See D. 04-12-048

Section III

RECOMMENDED REVISED MARKET PRICE BENCHMARK

As discussed in the DA and DL CRS Methodology sections of this report, the DWR Power Charge component of the CRS is based on the above-market cost of the combined DWR and IOU portfolios for each utility. These above-market costs are calculated with respect to a market price benchmark. The Working Group discussed several options for setting a market price benchmark and reached general agreement that a futures-based benchmark based on published futures prices for power is an appropriate measure for this purpose. This section discusses the rationale for such an approach, how such a futures-based benchmark could be derived, a comparison of the different methods for calculating such benchmarks that have been discussed by the Working Group, and a recommendation as to the benchmark methodology that should be adopted.

Working Group Recommendation

The Working Group recommends that a benchmark based on publicly available futures prices replace the weighted average spot purchase and sales benchmark that has been incorporated in previous DWR models. Most parties agree to the use of an average of power price futures for a one-year strip of power taken from October 1 through October 31 of the prior year, plus an adder to reflect the value of capacity/resource adequacy, to establish each year's benchmark, with separate benchmarks calculated for each IOU.[17] Compromise capacity/resource adequacy adders for 2006 have been incorporated into the agreement among the DA Agreement Parties attached to this report. Capacity/resource adequacy values for 2007 and beyond will be obtained based on publicly reported transactions in a California capacity/resource adequacy market or other suitable public index once available. The issue of a suitable adder to reflect capacity/resource adequacy value will be revisited for 2007 and beyond as warranted by progress in developing transparent and publicly reported values for capacity/resource adequacy.

Rationale for a futures-based benchmark

- ***Reflects procurement practices.*** A futures-based benchmark reflects the context of current resource adequacy requirements better than model-derived market prices, after-the-fact spot prices, or administrative values from other proceedings. Resource adequacy requirements dictate that the IOUs have 90% of their power forward-contracted or self-supplied a year in advance and rely on spot power for no more than 5% of their resources. The futures market provides publicly available estimates of the price the IOU would have to pay to serve the DA/DL load.

- ***Minimize the need for after-the-fact true-ups.*** The forecasted value of utility and DWR resources will be measured against the benchmark, whether separately or

[17] SDG&E prefers a gas futures-based benchmark and has not yet determined whether it will agree to a power futures-based benchmark.

combined. Any difference between these forecasts and actual costs will be accommodated via balancing accounts in the ERRA or DWR Revenue Requirement proceedings and will not require a separate true-up. The benchmark itself can be set at the beginning of the year and not be subject to change. Should drastic conditions occur that would prompt significant changes to the CRS market price benchmark, such a modification could be requested.

- ***Transparency***. Published futures prices provide transparency. All interested parties will be able to verify the benchmark value. This avoids a major concern of the "market participant" parties, who are blocked from reviewing the confidential utility data that would be needed if the benchmark were based on utility activity in power markets.

- ***Simplicity***. Using published forward prices, with minor adjustments, is simple and easily verifiable. It avoids using complex models (such as PROSYM) or other calculations that are not transparent to establish a market price benchmark.

Other Options Considered By the Working Group

The Working Group considered, but declined to recommend, several other approaches to a market price benchmark. These are described below:

- ***Historical spot prices:*** Under this approach, it would be necessary to determine a market price that is appropriate for the location and magnitude of the departing load. For example, the CAISO imbalance market would not be the market to buy, sell, or value 15% of the IOU load. This historically used benchmark does not properly simulate the hypothetical cost to serve the entire DA/DL load (i.e., it ignores resource adequacy requirements and general utility procurement planning).

- ***Actual IOU purchases from and sales into short term and spot markets****:* This approach would require that a benchmark be based on the average price of all IOU purchases and sales under non-QF contracts that made their *initial deliveries* in the given year (either the first year of contract deliveries for a term contract, or all deliveries under shorter term deals). This approach is limited due to the potentially large variations in the amounts of such power from year to year and the reliance on confidential utility data to determine these volumes and associated costs.

- ***Model-based:*** This approach would use a production cost simulation model to derive market clearing prices and has been used by the Commission in the past. The Working Group reviewed this approach for analysis of the CRS cap and for setting the prospective CRS values. Its limitations include lack of transparency, need for true-up and the assumption that DA/DL load should be valued at the spot

price (i.e., it ignores resource adequacy requirements and general utility procurement planning).

- ***Sell off excess power associated with departed load**:* Another approach to establish a benchmark would be for each utility to issue a Request for Proposal to mirror the contract structure of a portion of the DWR contracts associated with the DA/DL load profile, execute a contract to sell this energy supply and close out the position of any excess power received under the DWR contracts. The Indifference Rate would then be calculated as the costs of the power sold less revenue received from the Excess Supply Contracts.

- ***Bid-week gas prices:*** Base benchmark on gas futures price times heat rate plus an adder, with post-hoc true-up to actual bid-week gas prices. This approach would require a true-up and may be administratively burdensome.

- ***MPR plus One-Year Forward Gas Prices:*** The Market Price Referent (MPR) model, developed and reviewed in the Renewable Portfolio Standard proceeding (R.04-04-026) and adopted in D.04-06-15 and Resolution E-3942, is available for determining a forward electricity price. It was used in the calculation of the CTC benchmark in PG&E's 2006 ERRA proceeding (A.05-06-007, D.05-12-045). Futures contracts for natural gas at Henry Hub are traded on NYMEX and publications such as *Gas Daily* provide a publicly available source for indices of these contract prices that all interested parties could easily reference.

Each of these methods was proposed and discussed within the Working Group. However, it is the recommendation of the Working Group that a futures-based benchmark be applied, as it is an appropriate measure of the power being valued, it relies on readily available published data, it is capable of replication by other parties, and it can be projected over the necessary forecast period.

CONSENSUS RECOMMENDATION: Market Price Benchmark

The Working Group recommends that the benchmark for each year be calculated based on an average of one-year strip power futures quotes for NP 15 and SP 15 for the coming calendar year from *Megawatt Daily* published from October 1 through October 31 of the prior year, plus a capacity/resource adequacy adder. Separate benchmarks are to be calculated for PG&E, SCE and SDG&E, based on the futures market most relevant to each utility (NP15 or SP15) and the regional value of capacity/resource adequacy. These benchmarks are to be grossed up for line losses.

The recommended procedure for calculating the benchmark is as follows:

- Use an average of *Megawatt Daily* published market indices for a one-year strip of power prices for the coming calendar year for NP15 and SP15 published over the period October 1 through October 31 of the year prior to that being

considered.[18] For example, the 2007 benchmark would be based on an average of *MW Daily* calendar year 2007 power forward indices published for the period from October 1 through October 31, 2006. To determine the benchmark for 2006, the DA Agreement Parties have agreed to use one-year strips for the period 11/15/05 to 12/15/05 in the year 2005 for 2006 CRS calculations only because of the impact of Hurricanes Katrina and Rita during October 2005.

- Separately calculate this average for NP15 and for SP15. PG&E's benchmark would be based on NP15 prices; SCE and SDG&E benchmarks would be based on SP15 prices.
- Multiply the average quote by 0.87 to account for the fact that the benchmark is effectively for baseload power while the future price assumes a 6x16[19] product. The 0.87 multiplier is the average ratio of actual 24x7 spot prices and 6x16 spot prices.
- Add a capacity/resource adequacy adjustment to the futures prices. Because futures market prices may not adequately reflect capacity/resource adequacy costs, a capacity/resource adequacy component is added to forward NP15/SP15 prices. Generators in California today do not recover all fixed costs from the price-capped wholesale market. The need for a reflection of capacity/resource adequacy value is acknowledged by the Commission's efforts to develop a capacity/resource adequacy market as proposed in the recently issued white paper on capacity/resource adequacy markets ("California Public Utilities Commission Capacity/resource adequacy Markets White Paper," issued August 25, 2005). Such an adder also recognizes the cost of complying with resource adequacy requirements. The capacity/resource adequacy adder is further discussed below.
- Adjust for line losses. The portfolio prices against which the benchmark will be measured are at the customer meter. Therefore, to keep the comparison consistent, the benchmark would need to reflect the same average line losses that are inherent in the delivered power prices. These values have not yet been agreed upon by the Working Group. Line loss estimates range from 6.0%-8.5% for PG&E, 5.3%-8.4% for SCE, and 4.3% for SDG&E.[20]

Therefore, the Benchmarks (BMs) would equal:

$BM_{PG\&E,\ year\ N}$ = (Ave. Future quotes in $October_{NP15,\ year\ N-1}$ x 0.87 + Capacity/Resource Adequacy Adder $_{PG\&E,\ year\ N}$) x (1+Line $Losses_{PG\&E}$)

$BM_{SCE,\ year\ N}$ = (Ave. Future quotes in October $_{SP15,\ year\ N-1}$ x 0.87 + Capacity/Resource Adequacy Adder $_{SCE,\ year\ N}$) x (1+Line $Losses_{SCE}$)

$BM_{SDG\&E,\ year\ N}$ = (Ave. Future quotes in October $_{SP15,\ year\ N-1}$ x 0.87 + Capacity/Resource Adequacy Adder $_{SDG\&E,\ year\ N}$) x (1+Line $Losses_{SDG\&E}$)

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18 Alternatives raised in the Working Group include use of a 60-day strip of forward prices or a selection of forward price indices from throughout the prior year.

19 Delivery six days a week (Monday through Saturday), 16 hours a day (7 am to 11 pm).

20 Note that the sample values provided in the text do not include the line loss adjustment.

Development of a Capacity/Resource Adequacy Adder

Working Group members agree that an adder should be included in the benchmark calculation to reflect the values of capacity/resource adequacy. The need for a reflection of capacity/resource adequacy value is acknowledged by the Commission's efforts to develop a capacity/resource adequacy market as proposed in the recently issued white paper on capacity/resource adequacy markets ("California Public Utilities Commission Capacity/resource adequacy Markets White Paper," issued August 25, 2005). Such an adder also recognizes the cost of complying with resource adequacy requirements.

The DA Agreement Parties have incorporated negotiated capacity/resource adequacy adders in developing their agreed-upon 2005 EOY undercollection balances for PG&E and SCE and have also negotiated capacity/resource adequacy adder values for 2006, since there is no capacity/resource adequacy market available at the present time to provide transparent values.[21] The Working Group recommends that it be directed to reconvene in August 2006 to discuss and recommend capacity/resource adequacy adders for 2007 and beyond.

[21] Capacity/resource adequacy adders for 2006 have been negotiated as part of on-going workshop report discussions. Proposals have ranged from approximately $1.20/MWh-$9.60/MWh. The lower value of this range is based on PG&E's proposal to use the going-forward fixed cost needed to maintain a specific 300 MW steam unit on the PG&E system net of the energy benefit received from this unit. The higher value is based on CLECA, CMTA, and AReM's proposal to use the annual carrying cost of a combustion turbine.

Section IV

PROCEDURAL RECOMMENDATIONS AND DATA REQUIREMENTS

In Section II, the Working Group presents recommendations as to how the Commission should calculate the DWR Power Charge and IOU CTC, and IOU "new world" components of the CRS. Consistent with this approach, this section recommends a process for establishing these CRS components annually, and describes the data inputs that are necessary under this recommended approach.

DWR Power Charge CRS

The Working Group recommends that the Commission establish the Ongoing DWR Power Charge rate component of the CRS as part of the proceeding for allocating the DWR's revenue requirements to the three IOUs' customers (currently A.00-11-038). By August of the preceding year (or more frequently, if necessary), DWR generally notifies the Commission of its revenue requirement for the upcoming year. The Commission generally issues a proposed decision by November of the same year, which includes an inter-utility allocation of DWR costs and an inter-utility true-up of DWR costs for the year prior. For instance, in August 2006 DWR will notify the Commission of its 2007 revenue requirement and provide data necessary for the Commission to calculate any inter-utility true-up for 2005.

In order for the Commission to adopt a calculation of the DWR Power Charge component of the CRS, the following datasets are required:

(1) Cost and volume of utility owned generation operating prior to 2/1/01 – supplied by IOUs
(2) Forecasted DWR costs – supplied by DWR
(3) Forecasted DWR deliveries – supplied by DWR
(4) Forecasted bundled deliveries – supplied by DWR
(5) Forecasted direct access load for load that departed before July 1, 2001 – supplied by IOUs
(6) Forecasted direct access load for load that departed after February 1, 2001 – supplied by IOUs
(7) Forecasted self generating departing load, non-exempt from the DWR power charge CRS – supplied by IOUs
(8) Forecasted municipal departing load, non-exempt from the DWR power charge CRS – supplied by IOUs
(9) Market price benchmark – calculated consistent with section III
(10) Estimated end-of-year balances in the utility-specific balancing accounts.

DWR would provide items 2-4 and 10 (for the following year) contemporaneous with its revenue requirement determination. The IOUs would provide items 5-8 (for the following year) within 14 days of the submission of DWR's revenue requirement

determination. Item 9 would be calculated by the Commission's Energy Division, using data from October. All volumetric data would be provided at the customer meter in kWh format. All financial data would be reported in dollars.

IOU CTC, Total Portfolio Adjustment and IOU New World Power

The Working Group recommends that the IOUs establish these components of the CRS in their ERRA applications. If adopted by the Commission, and as applicable, the Total Portfolio Adjustment (as described in Section II-B) and New World Resources charges would also be established in the IOUs' ERRA proceedings. IOUs should include annual forecast data for the following cost and volume categories:

(1) utility owned generation operating prior to 2/1/01
(2) QF contracts
(3) inter-utility contracts executed prior to 2/1/01
(4) bilateral contracts executed prior to 2/1/01
(5) utility owned generation initial operation after 2/1/01 by calendar year
(6) inter-utility contracts executed after 2/1/01 by calendar year
(7) bilateral contracts executed after 2/1/01 by calendar year
(8) renewable generation/contracts executed after 2/1/01 by calendar year
(9) ISO excluding GMC
(10) volumes associated with items 1-8
(11) bundled volume non-exempt from the CTC
(12) direct access volume non- exempt from Old World CTC
(13) self generating departing load volume non-exempt from Old World CTC
(14) municipal departing load volume non-exempt from Old World CTC
(15) direct access volume non-exempt from New World power
(16) self generating departing load volume non-exempt from New World power
(17) municipal departing load volume non-exempt from New World power
(18) market price benchmark – calculated consistent with Section III
(19) spot market energy purchases/sales
(20) ISO charges associated with spot market energy purchases/sales

The Market Price Benchmark will be calculated by the Energy Division.

All volumetric data would be provided at the customer meter in kWh format. All financial data would be reported in dollars.

For data labeled as confidential, the Energy Division will need to ensure that the forecast costs and volumes and all other data included in the calculations are consistent with the IOUs' ERRA filings. On a going forward basis for all CRS obligations, and for DL CRS obligations from 2003-2006, the DL parties recommend that this process must be completed prior to any final Commission determination regarding these CRS charges.

DL Parties Concerns on Costs

1. The above-market IOU or DWR Portfolio cost is the average cost of IOU or DWR Power less the Market Price Benchmark. The average cost of IOU and DWR power reflected in this Report include the loads and costs associated with spot market energy purchases/sales and the related CAISO charges as well as the utility renewable generation /contracts load and costs. Consistent with the recommended market price benchmark, DL participants in the Working Group believe these costs and loads are properly assigned to the bundled customer and ought to be excluded from the CRS calculation of above-market IOU or DWR Portfolio costs.

2. To properly calculate customer indifference, DL participants believe that line losses reflected in this Report should appropriately reflect the IOU's "system" losses. The results reflected in this Report limit line losses to the calculation of "distribution" line losses. A change is needed to substitute "system" losses for "distribution" losses.

IOUs Response

1. With respect to spot market energy purchases/sales and the associated ISO costs, the IOUs agree that they should not be included in the new world URG cost calculations.
2. With respect to the cost of utility renewable generation, The IOUs believe these costs are appropriately reflected and allocated to all customers who have been found to be responsible for IOU or DWR power costs.
3. IOU and DWR power costs and deliveries already reflect transmission losses. "Distribution" losses are the appropriate measure of "system" losses to ensure consistent treatment of costs and volumes.

CRS Exemptions and Protocols For Administering The First-Come, First-Served Rules For POUs Seeking To Qualify For Authorized CRS Exclusions

Summary and Recommendation: The Working Group recommends that the January 31, 2005 POU proposal for allocation of transferred load exceptions from the CRS serve as the basis for the implementation protocols adopted by the Commission. The proposal should serve as the basis for protocols to apply to transferred departed load, as described below.

The working group had a preliminary discussion regarding allocation of exemptions for "new" departing load, but did not finalize protocols for this portion of departing load. The Energy Division acknowledges that due to time constraints and its delays in providing a draft proposal of these protocols, it may be necessary for the "protocols" subgroup of this Working Group to meet after the Commission issues its decision addressing this report, in order to finalize these protocols.

Introduction

MDL volumes that are not exempt from the DWR power charge component of the CRS are dependant upon the allocation of exemptions to the publicly owned utility (POU) service territories. These non-exempt MDL volumes are needed to allocate the DWR above market costs to responsible load accurately. Initial estimates by PG&E indicate, however, that given the current exemption levels adopted by the CPUC, no MDL in PG&E's service territory will owe the DWR power charge component for 2003-2005. This situation also may be the case for MDL in SCE and SDG&E's service territories.

The allocation of exemptions from the DWR power charge component to MDL and the subsequent calculation of non-exempt load is dependant upon the IOUs' ability to identify the volumes of load that qualify for the New MDL and Transferred MDL exemptions. Although the IOUs have indicated that they have the ability to reasonably estimate Transferred MDL due to the utility's prior relationship with the customer, they have less ability to identify New MDL, and will require the cooperation of the POUs to complete this task.

ALJ Pulsifer's March 28, 2005 Ruling (March 28th Ruling) establishing this Working Group noted that protocols for administering the "first-come, first-served" rules for POUs seeking to qualify for authorized CRS exclusions were discussed in the March 11, 2005 Energy Division Report on the January 31, 2005 workshop and directed that a Working Group be established to address necessary implementation measures regarding MDL CRS calculation. In the course of its work, the Working Group determined that calculation of the MDL CRS obligations could not be completed without developing the protocols referenced by the ruling. Thus, these protocols were cooperatively developed, discussed by the Working Group, and are presented below.

ALJ Pulsifer's December 23, 2004 Ruling (December 23rd Ruling) initiating the process to implement billing and collection frames issues relating to administration of the CRS exemption credits as follows:

> "in D.03-07-028, the Commission adopted provisions for publicly owned utilities to qualify for MDL CRS exclusions for "new load" on behalf of their customers. The manner as to how such exclusions are to be administered, however, was left to the billing and collection implementation phase. Furthermore, D.04-12-059 [which addressed applications for rehearing of D.04-11-014, the decision on rehearing of D.03-07-028] adopted MDL CRS exclusions for "new load" associated with (1) POUs serving in geographic areas identified in the PG&E Bypass Report for "transferred load" and (2) POUs formed before July 2003 capped on an interim basis at 80 MW."

The December 23rd Ruling accordingly solicited proposals concerning, among other items, specific protocols for administering the first-come, first-served rules for POUs seeking to qualify for authorized CRS exclusions.

The January 31, 2005 workshop reached a productive outcome on this question for the category of "transferred load". Representatives of certain POUs with transferred load presented a joint proposal for "Allocation of Transferred Load Exceptions From the CRS".

As a framework for developing the protocols that should be adopted by the Commission, the salient points of the January 31, 2005 POU proposal are repeated below, in italicized text. A few clarifying edits added to the original proposal are shown in square brackets.

The purpose of this document is to provide a proposal for administering the Megawatt-hour (MWh) exceptions from the CRS allocated to transferred MDL, as adopted in D.04-11-014, as modified by D.04-12-059[22].

The following principles should be used in implementing the transferred load CRS exceptions:

- *CRS will be assessed as a volumetric charge based on historical pre-departure metered consumption:*
  - *Historical pre-departure metered data will be determined as recorded in each customer's departing load statement.*
  - *IOUs will cooperate in providing copies of each customer's departing load statement to the serving POU.*

- *POUs' determination of the amount of load eligible for an annual exception shall be done on an annual basis.*

[22] Note that D.04-12-059 was clarified in D.05-07-038, which was issued after the January 2005 workshop.

- *POUs will provide the amount of their transferred load exception for the previous year to DWR by February 1 of the following year:*
    - *Priority allocation for transferred load CRS exceptions shall be (1) entities named in the Bypass Report up to the full amount set forth in the report, followed by; (2) POUs with customers departing PG&E bundled service on a first-come, first-served basis, followed by; (3) all other eligible POUs on a first-come, first-served basis.*
    - *Each year entities named in the Bypass Report have priority for up to the full amount set forth in the Report; however, once established the priority for allocating excess exceptions will be followed each year.*

- *Any exception amount not used in a calendar year remains available for [use by qualifying DL in] subsequent years.*

- *POUs are not required to provide any customer specific information to the IOUs.*

- *[Each year, the] CRS transferred load exceptions are assigned to the load of a POU, and not to particular customers.*

- *Payment of CRS will be for the preceding year.*

- *For entities not named in the Bypass Report, first-come, first-served priority for the CRS exception should be determined on the date the affected service area came under the control of the POU (by annexation, agreement or otherwise).*

- *Any collection costs incurred by the IOU are the responsibility of the IOU.*

The working group recommends that, as applicable, these principals be applied to protocols for the "first-come, first-served" exceptions provided to transferred departing load. Separate protocols will be necessary for new load.

On October 3, 2005 interested members of the working group met to discuss and develop recommended protocols, and used the January 31, 2005 POU proposal as their starting point for specific protocols that can be implemented by the Commission. At the meeting, PG&E agreed to compile its confidential load data for each affected POU and to provide that data to the Energy Division for distribution. The Energy Division did so on November 2, 2005 and has not heard of any issues that could not be resolved by direct discussions between PG&E and the affected POU.

<u>Conversion Of MW Cap Into MWH Figure</u>

The December 23, 2004 and January 26, 2005 ALJ Rulings called for the IOUs to "provide system average load factors…from which the applicable MW caps can be converted into a corresponding MWH figure." PG&E and Edison provided preliminary load factor figures at the January 31, 2005 workshop and confirmed those figures in follow-up communications with the Energy Division.

The December 23, 2004 ALJ Ruling also requested comments on the appropriate methodology for converting the 80 MW cap into a MWH figure. In its January 14, 2005 opening comments, PG&E proposed that the 80 MW cap be multiplied by 8,760 hours per year, which should then be multiplied by a system average load factor. No party expressed any objection to this approach.
In its April 15, 2005 comments, DWR indicated it did not wish to administer the program. As a result, the Energy Division recommends that it take on this responsibility itself. The Energy Division proposes the following timeline and milestones.

Recommended Protocols for Transferred Departing Load and New Departing Load

Transferred Load:

For transferred load, the Bypass Report shall serve as the starting point for listing the individual POUs that are eligible for the "first tier" exemptions, and for specifying the total amount of transferred load for which load served by the POUs may be exempted from paying specified CRS charges.

Step #1: Fifteen days following a Commission decision adopting these protocols, each POU listed in the Bypass Report will confirm to the Energy Division either that the data provided to them by PG&E is correct, or report on mutual resolution of any discrepancies (as noted above, the necessary data for transferred load was distributed to each POU on November 2, 2005). Thereafter, starting February 1, 2007, each POU shall, on or before February 1, provide to the Energy Division the amount of their transferred load exception for the previous calendar year.

Step #1a: Within 5 business days, the Energy Division will notify the service list of total and POU-specific excepted load, and by charge type, and show the remaining exceptions available by charge type. If necessary for confidentiality reasons, Energy Division will provide only total amounts for each IOU service area. At the request of DL parties, the Energy Division will determine whether this information can be posted on the Commission website.

Step #2: Within 10 business days of the release of this information by the Energy Division, "non-bypass report POUs" **with customers departing PG&E bundled service** may notify the Energy Division of their interest in the available unused exemptions, and will provide an estimate of their exempted load, and will identify each charge type for which they claim they are exempt, along with a citation to the relevant Commission order that established this exemption.

Step #2a: Within 5 business days, the Energy Division will compile and distribute the proposed list of exemptions to IOUs to verify the information is correct, or report on mutual resolution of any discrepancies.

Step #2b: Within 5 business days, the Energy Division will notify the service list of the results of this round of total and POU-specific excepted load, and by charge type, and show the remaining exceptions available by charge type. If necessary for confidentiality reasons, Energy Division will provide only total amounts for each IOU service area.

Step #3: Within 10 business days of this notification by the Energy Division **all other POUs with transferred MDL** may notify the Energy Division of their interest in the remaining available unused exemptions, and will provide an estimate of their exempted load, and will identify each charge type for which they claim they are exempt, along with a citation to the relevant Commission order that established this exemption.

Step #3a: Within 5 business days, the Energy Division will compile and distribute the proposed list of exemptions to IOUs to verify that the information is correct, or report on mutual resolution of any discrepancies.

> As specified in the January 31, 2005 POU proposal, in the event that the limit of exemptions is reached, prioritization for available exemptions will be as follows:
>
> *"for entities not named in the Bypass Report, first-come, first-served priority for the CRS exemption should be determined on the date the affected service area came under the control of the POU (by annexation, agreement or otherwise)."* Furthermore, because the exceptions are applied on an annual basis, and each year entities named in the Bypass Report have priority for up to the full amount set forth in the Report, should the cap on the total MW exemptions be reached and an entity named in the Bypass Report has not utilized the full amount allotted to that entity in the Bypass Report, exemptions allocated to other POUs in the previous year may be lost, beginning with those last-served.

Step #4: Within 5 business days the IOUs will provide verification and their agreement with the budgeted allocation of exemptions.

Step #5: Within 5 business days the Energy Division will finalize the exemptions and distribute this information to the affected POUs, IOUs and DWR.

Step #6: In the event a dispute regarding the allocation of exemptions cannot be resolved through informal negotiation between the parties or the Energy Division, such dispute may be appealed. The outcome of any such appeal shall be based on the procedural steps set forth above.

New MDL:

As noted above, the Working Group briefly discussed, but did not attempt to develop protocols for new MDL exemptions. As noted above, this may in part be due to delays that may be laid at the feed of the Energy Division. Participants do appear to agree that protocols still need to be developed for "new" MDL exemptions, and also appear to agree that it is possible that the transferred load exemption protocols outlined above may at least be useful as a starting point for that task. The Energy Division believes that protocols for new load could be developed quickly if the affected POUs and IOUs were willing to work together in collaborative fashion to do so. However, the Energy Division believes that it may be necessary for the assigned ALJ to work directly with both sides to identify and resolve stumbling blocks and accomplish this goal.

Conclusion

The working group recommends adoption of the protocols outlined above for transferred load. Once these protocols are adopted by the Commission, the Energy Division can

continue to work with the affected POUs and IOUs, to complete the tasks listed above and identify all the entities eligible for the various CRS exclusions authorized by the Commission.

The Energy Division understands that the amount of actual transferred departed load and new departed load in the IOU service territories is currently well below the total exemptions available. However, these protocols will serve to allocate exemptions for transferred load when and if such exemption limits are reached.

Section V

RESULTS

This section presents the results of numerical analyses prepared by the Working Group to support the recommendations in this report. These results are based on data and cost allocations developed and provided by the IOUs and DWR, much of which is confidential and has not been provided to the other Working Group participants. The calculations and results are provided here to show the application of the recommended methodologies and benchmarks numerically, and to provide a reasonable range of outcomes for purposes of assessing the current cap on CRS charges. As the Commission adopts these CRS obligations on a going forward basis, and the DL CRS obligations from 2003-2006, and resolves questions regarding the appropriate cost components and loads to include in the calculations, the Energy Division will verify the data inputs used and modeling methodology applied.

Direct Access 2003-05 CRS Obligations

ALJ Pulsifer's March 30, 2005 Ruling directed the Working Group to calculate direct access CRS obligations for 2003 on a true-up basis and for 2004 and 2005 on a forecast basis. The Tables below show the results based on three different benchmark methodologies. While the Working Group members did not agree on a revised methodology for the period 2003-05, they have reached agreement on the values for the undercollection balances as of the end of 2005, given the range of potential methodologies for the 2003-2005 period.

Table 1A – Table 1C provide the direct access CRS accrual rates for each IOU service territory for the period 2003-05 and 2003-2011, as follows:

Table 1A	2003-05 CRS accrual rates based on the benchmark adopted in D.05-01-040
Table 1B	2006-2011 CRS accrual rates based on the benchmark adopted in D.05-01-040
Table 1C	2006-2011 CRS accrual rates based on the Working Group recommended benchmarks

Table 1C, along with the EOY 2005 undercollection balances shown in Table 2B, represents the recommendation of the DA Agreement Parties. The other tables are provided in order to place the recommendation into larger context.

Table 2A and Table 2B provide the resulting year end CRS balances, taking into account actual or forecast CRS collections and interest on any undercollection.

Table 2A	2003-2005 CRS balances based on benchmark adopted in D.05-01-040, excluding DWR bond charge undercollections
Table 2B	Forecast DA CRS Undercollection Balance Paydowns, including DWR bond charge undercollections

Table 2B represents the recommendation of the DA parties. The results in Table 2A were calculated using the methodology and benchmark adopted in Decision 05-01-040, the Commission's decision on the 2001-2002 period.

Table 1A

2003-05 DA CRS Accrual Rates Based on Benchmark Adopted in D.05-01-040

DIRECT ACCESS	2003	2004	2005
DA Indifference Rate ($/MWh)			
PG&E	20.15	18.24	1.29
SCE	23.02	19.63	11.84
SDG&E	15.91	15.62	3.33
CTC ($/MWh)			
PG&E	-	1.76	5.13
SCE	-	2.65	0.33
SDG&E	6.80	6.80	5.96
DA Power Charge Rate ($/MWh)			
PG&E	20.15	16.48	-
SCE	23.02	16.98	11.51
SDG&E	9.11	8.82	-

Table 1B

DA CRS Accrual Rates Based on Benchmark Adopted in D.05-01-040

DIRECT ACCESS	2006	2007	2008	2009	2010	2011
DA Indifference Rate ($/MWh)						
PG&E	3.48	5.77	-	4.00	9.08	1.82
SCE	17.78	16.85	3.41	8.26	(1.63)	(7.62)
SDG&E	2.80	4.57	7.85	9.79	4.55	0.42
CTC ($/MWh)						
PG&E	3.10	3.10	3.10	3.10	3.10	3.10
SCE	7.87	7.87	7.87	7.87	7.87	7.87
SDG&E	5.96	5.96	5.96	5.96	5.96	5.96
DA Power Charge or PCIA Rate ($/MWh)						
PG&E	0.38	2.67	-	0.90	5.98	-
SCE	9.91	8.98	-	0.39	-	-
SDG&E	-	-	1.89	3.83	-	-

Table 1C

DA CRS Accrual Rates Based on Working Group Recommended Benchmarks

DIRECT ACCESS	2006	2007	2008	2009	2010	2011
DA Indifference Rate ($/MWh)						
PG&E	-	-	-	-	6.64	9.73
SCE	(10.40)	(6.92)	(3.35)	-	-	4.99
SDG&E	-	-	1.10	0.71	-	4.57
CTC ($/MWh)						
PG&E	3.10	3.10	3.10	3.10	3.10	3.10
SCE	7.87	7.87	7.87	7.87	7.87	7.87
SDG&E	5.96	5.96	5.96	5.96	5.96	5.96
DA Power Charge or PCIA Rate ($/MWh)						
PG&E	(3.10)	(3.10)	(3.10)	(3.10)	3.54	6.63
SCE	(18.27)	(14.79)	(11.22)	(7.87)	(7.87)	(2.88)
SDG&E	(5.96)	(5.96)	(4.86)	(5.25)	(5.96)	(1.39)

Table 2A[23]

2003-05 DA CRS DWR Power Charge Obligations Based on Benchmark Adopted in D.05-01-040

All values in dollars

DIRECT ACCESS	PG&E	SCE	SDG&E
2002 Balance	234,870,000	354,751,000	42,696,000
2003 Accruals + Interest	171,319,351	274,011,749	21,443,496
2003 Collections	196,095,516	179,141,000	32,948,874
2003 Balance	210,093,835	449,621,749	31,190,622
2004 Accruals + Interest	152,330,303	209,592,539	18,388,169
2004 Collections	110,580,166	124,286,000	30,248,171
2004 Balance	251,843,972	534,928,288	19,330,620
2005 Accruals + Interest	10,904,844	152,011,359	837,016
2005 Collections	106,150,101	135,235,600	20,167,635
2005 Balance	156,598,714	551,704,047	-

[23] EOY 2005 undercollection balances shown **do not include** bond charge undercollection balances.

Table 2B[24]

Forecast DA CRS Undercollection Balance for Direct Access Load in PG&E Service Territory
Based on Working Group Recommended EOY 2005 Balances and Working Group Recommended Benchmarks 2006-2011

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
DWR Bond Accrual Rate ($/MWh)					4.85	5.14	5.14	5.07	5.07	4.80
HPC/DRC Accrual Rate ($/MWh)				5.07	4.24	4.32	4.46	4.60	4.74	4.90
CTC Accrual Rate ($/MWh)				5.13	3.10	3.10	3.10	3.10	3.10	3.10
DWR Power Charge Accrual Rate ($/MWh)					(21.56)	-	-	-	3.54	6.63
DWR Power Charge Collection Rate ($/MWh)					(14.36)	(0.00)	(0.00)	(0.00)	3.54	6.63
DA Non Exempt Load (MWh)					8,693,702	8,693,702	8,693,702	8,693,702	8,693,702	8,693,702
Power Charge Accruals ($)					(187,402,147)	-	-	-	30,795,801	57,674,378
Power Charge Collections ($)					(124,804,147)	(0)	(0)	(0)	30,795,801	57,674,378
Annual Under/(Over) Collection ($)					(62,598,000)	0	0	0	-	-
Interest ($)					2,598,000	(0)	(0)	(0)	(0)	(0)
Year End Balance ($)				60,000,000	(0)	(0)	(0)	(0)	(0)	(0)

Forecast DA CRS Undercollection Balance for Direct Access Load in SCE Service Territory
Based on Working Group Recommended EOY 2005 Balances and Working Group Recommended Benchmarks 2006-2011

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
DWR Bond Accrual Rate ($/MWh)					4.85	5.14	5.14	5.07	5.07	4.80
HPC/DRC Accrual Rate ($/MWh)				10.00	10.00					
CTC Accrual Rate ($/MWh)				0.33	7.87	7.87	7.87	7.87	7.87	7.87
DWR Power Charge Accrual Rate ($/MWh)					(18.35)	(14.86)	(11.29)	-	-	-
DWR Power Charge Collection Rate ($/MWh)					4.28	13.99	(7.49)	0.00	0.00	-
DA Non Exempt Load (MWh)					11,195,000	11,195,000	11,195,000	11,195,000	11,195,000	11,195,000
Power Charge Accruals ($)					(205,429,043)	(166,358,105)	(126,419,574)	-	-	-
Power Charge Collections ($)					47,914,600	156,592,039	(83,867,076)	0	0	-
Annual Under/(Over) Collection ($)					(253,343,643)	(322,950,144)	(42,552,498)	(0)	(0)	-
Interest ($)					24,984,100	15,096,132	1,766,053	0	0	-
Year End Balance ($)				577,000,000	348,640,457	40,786,445	0	0	-	-

Forecast DA CRS Undercollection Balance for Direct Access Load in SDG&E Service Territory
Based on Working Group Recommended EOY 2005 Balances and Working Group Recommended Benchmarks 2006-2011

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
DWR Bond Accrual Rate ($/MWh)					4.85	5.14	5.14	5.07	5.07	4.80
HPC/DRC Accrual Rate ($/MWh)										
CTC Accrual Rate ($/MWh)				5.96	5.96	5.96	5.96	5.96	5.96	5.96
DWR Power Charge Accrual Rate ($/MWh)				2.28	-	-	-	-	-	-
DWR Power Charge Collection Rate ($/MWh)					-	-	-	-	-	-
DA Non Exempt Load (MWh)					1,932,559	1,932,559	1,932,559	1,932,559	1,932,559	1,932,559
Power Charge Accruals ($)					-	-	-	-	-	-
Power Charge Collections ($)					-	-	-	-	-	-
Annual Under/(Over) Collection ($)					-	-	-	-	-	-
Interest ($)					-	-	-	-	-	-
Year End Balance ($)				-	-	-	-	-	-	-

[24] EOY 2005 undercollection balances shown **include** bond charge undercollection balances.

Departing Load 2001-2005 CRS Obligations

ALJ Pulsifer's March 28, 2005 Ruling directed the Working Group to "produce the calculations required for the Commission to adopt the MDL CRS obligations to date". Although, based on data provided by the utilities to the Energy Division as part of this working group process, it appears that for the period 2001-2004 all MDL was exempt from the DWR Power Charge component of the DL CRS, the MDL CRS accrual rates are provided below. No specific information has been provided for 2005, though appears that no MDL will be responsible for the DWR Power Charge component of the CRS for this period, either.

Table 3A	2003-2011 based on benchmark adopted in D.05-01-040
Table 3B	2003-2011 based on benchmark adopted in D.05-01-040 and 2006-2011 based on the Working Group recommended benchmarks
Table 3C	2003-2011 Working Group recommendations

Table 3A

MDL CRS Accrual Rates Based on Benchmark Adopted in D.05-01-040

MDL 2003 VINTAGE

MDL Indifference Rate ($/MWh)	2003	2004	2005	2006	2007	2008	2009	2010	2011
PG&E	21.69	20.71	1.46	3.95	6.55	(1.95)	4.55	10.31	2.07
SCE	23.51	20.05	12.09	18.15	17.20	3.48	8.43	(1.67)	(7.78)
SDG&E	43.64	37.03	7.91	6.64	10.85	18.62	23.22	10.78	1.01
MDL New World NBC ($/MWh)									
PG&E	(0.29)	0.15	-	-	-	-	-	-	-
SCE	0.65	0.71	-	-	-	-	-	-	-
SDG&E	0.27	0.04	-	-	-	-	-	-	-
MDL CTC ($/MWh)									
PG&E	-	7.02	5.15	3.10	3.10	3.10	3.10	3.10	3.10
SCE	-	11.79	11.69	7.87	7.87	7.87	7.87	7.87	7.87
SDG&E	6.80	6.80	5.96	5.96	5.96	5.96	5.96	5.96	5.96
MDL Power Charge Rate ($/MWh)									
PG&E	21.98	13.55	-	0.85	3.45	-	1.45	7.21	-
SCE	22.86	7.55	0.40	10.28	9.33	-	0.56	-	-
SDG&E	36.57	30.19	1.95	0.68	4.89	12.66	17.26	4.82	-

MDL 2004 VINTAGE

MDL Indifference Rate ($/MWh)	2004	2005	2006	2007	2008	2009	2010	2011
PG&E	20.79	1.46	3.95	6.55	(1.95)	4.55	10.31	2.07
SCE	20.40	12.09	18.15	17.20	3.48	8.43	(1.67)	(7.78)
SDG&E	37.06	7.91	6.64	10.85	18.62	23.22	10.78	1.01
MDL New World NBC ($/MWh)								
PG&E	0.53	-	-	-	-	-	-	-
SCE	0.77	-	-	-	-	-	-	-
SDG&E	0.56	-	-	-	-	-	-	-
MDL CTC ($/MWh)								
PG&E	7.02	5.15	3.10	3.10	3.10	3.10	3.10	3.10
SCE	11.79	11.69	7.87	7.87	7.87	7.87	7.87	7.87
SDG&E	6.80	5.96	5.96	5.96	5.96	5.96	5.96	5.96
MDL Power Charge Rate ($/MWh)								
PG&E	13.23	-	0.85	3.45	-	1.45	7.21	-
SCE	7.84	0.40	10.28	9.33	-	0.56	-	-
SDG&E	29.69	1.95	0.68	4.89	12.66	17.26	4.82	-

Table 3B

MDL CRS Accrual Rates Based on Benchmark Adopted in D.05-01-040 for 2003-05 and Working Group Recommended Benchmarks 2006-201. (Pending a Commission decision on the negative component of the CRS (an issue identified in this report), once the CRS undercollection has been paid, the Indifference Rate was limited to amounts greater than zero.)

MDL 2003 VINTAGE

MDL Indifference Rate ($/MWh)	2003	2004	2005	2006	2007	2008	2009	2010	2011
PG&E	21.69	20.71	1.47	(20.96)	-	-	-	7.55	11.06
SCE	23.51	20.05	12.09	(10.70)	-	-	-	-	5.04
SDG&E	43.64	37.03	7.91	(23.06)	-	2.62	1.69	-	10.83
MDL New World NBC ($/MWh)									
PG&E	(0.29)	0.15	-	-	-	-	-	-	-
SCE	0.65	0.71	-	-	-	-	-	-	-
SDG&E	0.27	0.04	-	-	-	-	-	-	-
MDL CTC ($/MWh)									
PG&E	-	7.02	5.15	3.10	3.10	3.10	3.10	3.10	3.10
SCE	-	11.79	11.69	7.87	7.87	7.87	7.87	7.87	7.87
SDG&E	6.80	6.80	5.96	5.96	5.96	5.96	5.96	5.96	5.96
MDL Power Charge Rate ($/MWh)									
PG&E	21.98	13.55	-	(24.06)	(3.10)	(3.10)	(3.10)	4.45	7.96
SCE	22.86	7.55	0.40	(18.57)	(7.87)	(7.87)	(7.87)	(7.87)	(2.83)
SDG&E	36.57	30.19	1.95	(29.02)	(5.96)	(3.34)	(4.27)	(5.96)	4.87

MDL 2004 VINTAGE

MDL Indifference Rate ($/MWh)	2004	2005	2006	2007	2008	2009	2010	2011
PG&E	20.79	1.47	(20.96)	-	-	-	7.55	11.06
SCE	20.40	12.09	(10.70)	-	-	-	-	5.04
SDG&E	37.06	7.91	(23.06)	-	2.62	1.69	-	10.83
MDL New World NBC ($/MWh)								
PG&E	0.53	-	-	-	-	-	-	-
SCE	0.77	-	-	-	-	-	-	-
SDG&E	0.56	-	-	-	-	-	-	-
MDL CTC ($/MWh)								
PG&E	7.02	5.15	3.10	3.10	3.10	3.10	3.10	3.10
SCE	11.79	11.69	7.87	7.87	7.87	7.87	7.87	7.87
SDG&E	6.80	5.96	5.96	5.96	5.96	5.96	5.96	5.96
MDL Power Charge Rate ($/MWh)								
PG&E	13.23	-	(24.06)	(3.10)	(3.10)	(3.10)	4.45	7.96
SCE	7.84	0.40	(18.57)	(7.87)	(7.87)	(7.87)	(7.87)	(2.83)
SDG&E	29.69	1.95	(29.02)	(5.96)	(3.34)	(4.27)	(5.96)	4.87

Table 3C

MDL CRS Accrual Rates Recommended by Working Group (Pending a Commission decision on the negative component of the CRS (an issue identified in this report), once the CRS undercollection has been paid, the Indifference Rate was limited to amounts greater than zero.)

MDL 2003 VINTAGE

MDL Indifference Rate ($/MWh)	2003	2004	2005	2006	2007	2008	2009	2010	2011
PG&E	10.73	12.96	7.79	(21.64)	-	-	-	9.13	8.71
SCE	17.19	16.22	6.76	(12.88)	-	-	-	-	1.10
SDG&E	38.24	28.89	8.13	(17.47)	-	20.34	18.08	12.66	35.84
MDL New World NBC ($/MWh)									
PG&E	(1.10)	(0.06)	-	-	-	-	-	-	-
SCE	0.48	0.41	-	-	-	-	-	-	-
SDG&E	0.06	(0.02)	-	-	-	-	-	-	-
MDL CTC ($/MWh)									
PG&E	-	7.02	5.15	3.10	3.10	3.10	3.10	3.10	3.10
SCE	-	11.79	11.69	7.87	7.87	7.87	7.87	7.87	7.87
SDG&E	6.80	6.80	5.96	5.96	5.96	5.96	5.96	5.96	5.96
MDL Power Charge Rate ($/MWh)									
PG&E	11.83	6.00	2.64	(23.75)	(3.10)	(3.10)	(3.10)	6.03	5.61
SCE	16.70	4.02	(4.93)	(20.75)	(7.87)	(7.87)	(7.87)	(7.87)	(6.77)
SDG&E	31.37	22.11	2.17	(23.43)	(5.96)	14.38	12.12	6.70	29.88

MDL 2004 VINTAGE

MDL Indifference Rate ($/MWh)	2004	2005	2006	2007	2008	2009	2010	2011
PG&E	12.93	7.79	(21.64)	-	-	-	9.13	8.71
SCE	16.42	6.76	(12.88)	-	-	-	-	1.10
SDG&E	28.88	8.13	(17.47)	-	20.34	18.08	12.66	35.84
MDL New World NBC ($/MWh)								
PG&E	(0.28)	-	-	-	-	-	-	-
SCE	0.46	-	-	-	-	-	-	-
SDG&E	(0.20)	-	-	-	-	-	-	-
MDL CTC ($/MWh)								
PG&E	7.02	5.15	3.10	3.10	3.10	3.10	3.10	3.10
SCE	11.79	11.69	7.87	7.87	7.87	7.87	7.87	7.87
SDG&E	6.80	5.96	5.96	5.96	5.96	5.96	5.96	5.96
MDL Power Charge Rate ($/MWh)								
PG&E	6.19	2.64	(24.74)	(3.10)	(3.10)	(3.10)	6.03	5.61
SCE	4.18	(4.93)	(20.75)	(7.87)	(7.87)	(7.87)	(7.87)	(6.77)
SDG&E	22.28	2.17	(23.43)	(5.96)	14.38	12.12	6.70	29.88

The data inputs and calculations used to generate these results are provided in Appendix C.

Section VI

CRS CAP AND UNDERCOLLECTION PAYDOWN PERIODS

In D.02-11-022 and D.03-07-030, the Commission set a CRS cap for DA load at 2.7 cents per kWh. The CRS cap was reviewed first in the summer of 2003, in hearings leading to D.03-07-030. The Commission at that time retained the 2.7 cent/kWh CRS cap, but decided to review it every two years. At the same time, the Commission indicated that it would raise the cap if the DA CRS undercollection did not appear likely to be paid off by the time the DWR power contracts expired (2011-2012).

ALJ Pulsifer's June 2, 2005 Ruling directed the Working Group to "assess whether, or to what extent, the 2.7 cents/kWh DA CRS cap should be revised prospectively, consistent with the objectives of D.03-07-030." In order to accomplish this task, the Working Group updated forecasts of CRS obligations through 2011. [25]

DWR/Navigant prepared two forecasts of CRS obligations through 2011. The first forecast, contained in Table 2A, applies the benchmark and modeling approach used to date to calculate CRS obligations. This includes a market price benchmark equal to the weighted average purchase and sale of short term power by the utility in a given year and limits the DWR Power Charge component of the CRS to a non-negative number.

The second forecast, contained in Tables 2B and 2C, applies the benchmark proposed by the Joint Parties from 2006-11 (see Section III), and does not limit the DWR Power Charge component of the CRS to a non-negative number during this same period.

Although this report contains other proposed changes to the methodology and benchmark (mostly non-consensus viewpoints), it is important to note that the forecasts contained in Table 2A and Table 2C may be considered to represent the upper and lower estimates for the paydown of the CRS undercollection.

The data inputs and calculations used to generate these results are provided in Appendix C.

<u>Working Group Analysis:</u>

As directed by ALJ Pulsifer, the Working Group has analyzed the question of whether the undercollection obligations of DA customers of each utility are forecast to be fully paid off by the time that the DWR contracts expire, under various proposed Indifference Rate methodologies for each utility. If the payoff is forecast to occur by that time, then there is no reason to increase the cap.

DWR's consultant prepared reports and associated tables for the Working Group showing that the paydown period for the DA CRS undercollection for all three utilities occurs

[25] In D.03-07-030, Finding of Fact #3, the Commission stated, "a reasonable criterion for purposes of preserving bundled customer indifference with respect to DA load migration is to ensure full payback of the DA CRS undercollection no later than the end of the DWR contract term expected to occur in 2011. In fact, the last DWR contract does not expire until 2015, but the vast majority of contracts expire by 2011.

several years before the DWR contracts expire using either the Commission-adopted methodology or the proposed methodology based on one-year strip purchases plus a capacity/resource adequacy price adder adjustment. In addition, there is general support for updating the Indifference Rate methodology as discussed earlier in this report. Thus, it is clear that the Commission's requirement that the undercollection be paid off by the expiration of DWR's contracts will be met and there is no reason to change the DA CRS cap from 2.7 cents/kWh. It is also clear that the SDG&E undercollection will be paid off in 2005.

CONSENSUS RECOMMENDATION DA#6: In D.02-11-022 and D.03-07-030, the Commission set a CRS cap for DA load at 2.7 cents per kWh. The Working Group recommends that the cap should remain at this level.

Because the SDG&E overcollection will be paid off in 2005, SDG&E filed Advice Letter 1726-E, and Advice Letter 1726-E-A (replacing AL 1726-E in its entirely) proposing to suspend the DWR Power Charge component of the CRS as of November 15th, 2005 in order to avoid significantly large overcollections on an ongoing basis. The Energy Division approved this advice letter, so DWR will not receive any Power Charge revenues from SDG&E's DA customers in 2006. SDG&E may file to reinstate the charge in the future depending on the methodology and benchmark adopted from the current proceeding and their effects on future DA CRS charges. SDG&E will file an advice letter, pending a final Commission decision in the instant proceeding, to credit from bundled to DA Non-Exempt customers the overcollection amount resulting from the time lag of when the historical undercollection was paid off in 2005 and when the charge was set to zero on November 15. 2005.

Table 1
CRS CAP AND UNDERCOLLECTION PAYDOWN PERIODS

Utility	Current Methodology *	Recommended Methodology**
	Year Paydown Completed	Year Paydown Completed
PG&E	2008	2006
SCE	2011	2008
SDG&E	2005	2005

*Uses Currently Adopted (Navigant) Methodology based on spot (i.e. less than 90 days) prices and sales as market Price Benchmark.

** Uses DA Agreement Parties' Recommended Methodology based on use of one-year strips plus a capacity/resource adequacy value to set Market Price Benchmark.

Source: Navigant January 24, 2006 model results provided to CRS Working Group.

Appendix A

Computational Examples

Appendix 1A
DWR Power Charge Accrual Rate
Historical Methodology

Row	Description	Calculation	
Input Data			
[9]	Bundled Load Served by IOU Power (MWH)	Supplied by IOU	50,000,000
[11]	Bundled Load Served by DWR Power (MWH)	DWR Revenue Requirement	15,000,000
[13]	Average Cost of Old World IOU Power ($/MWH)	Supplied by IOU	$85.00
[15]	Average Cost of DWR Power ($/MWH)	DWR Revenue Requirement	$90.00
[17]	DA DWR Power Charge Migrating Load After 2.1.01 (MWH)	Supplied by IOU	12,000,000
[19]	DA DWR Power Charge Migrating Load After 7.1.01 (MWH)	Supplied by IOU	11,000,000
[21]	DA Non-Exempt CTC Migrating Load (MWH)	Supplied by IOU	12,500,000
[23]	DL DWR Power Charge Non-Exempt Migrating Load (MWH)	Supplied by IOU	80,000
[25]	DL CTC Non-Exempt Migrating Load (MWH)	Supplied by IOU	85,000
[27]	Market Price Benchmark ($/MWH)		
[28]	Spot Market Purchases/Sales	Supplied by IOU	$50.00
[29]	ERRA	CPUC Proceeding	$60.00
[30]	Forecasted 1-Year Energy Prices	Energy Commission	$65.00
[32]	Line Losses (%)	Supplied by IOU	8.00%
[34]	CTC Accrual Rate	IOU ERRA	$12.00
[35]	New World Procurement Accrual Rate	IOU ERRA	$5.00
DWR Power Charge Accrual Rate (Total Portfolio Methodology)			
[40]	Average Cost of Old World Bundled Portfolio ($/MWH)	(([9]*[13])+([11]*[15]))/([9]+[11])	$86.15
[41]	Market Price Benchmark Adjusted for Line Losses ($/MWH)	[28] X (1+[32])	54.00
[42]	Above-Market Old World Bundled Portfolio Costs ($/MWH)	[40] - [41]	$32.15
[44]	Bundled Load (MWH)	[9] + [11]	65,000,000
[45]	Above-Market Old World Bundled Load Portfolio Costs ($)	[42] X [44]	$ 2,090,000,000
[47]	Above-Market Old World Bundled Load Portfolio Costs Allocated to ($):		
[48]	Bundled Load	(([9]+[11]) X [45])/([9]+[11]+[19]+[23])	$ 1,785,620,400
[49]	DA Load	([19] X [45])/([9]+[11]+[19]+[23])	302,181,914
[50]	DL Load	([23] X [45])/([9]+[11]+[19]+[23])	2,197,687
[51]	Total	[48] + [49] + [50]	$ 2,090,000,000
[53]	DA Indifference Rate ($/MWH)	[49] / [17]	$25.18
[54]	ERRA CTC Accrual Rate ($/MWH)	[34]	(12.00)
[55]	DA DWR Power Charge Accrual Rate ($/MWH)	[53] - [54]	$13.18
[57]	DL Indifference Rate ($/MWH)	[50] / [23]	$27.47
[58]	ERRA CTC Accrual Rate ($/MWH)	[34]	(12.00)
[59]	DL DWR Power Charge Accrual Rate ($/MWH)	[57] - [58]	$15.47

Appendix 1B
DWR Power Charge Accrual Rate
Consensus Recommendation

Row	Description	Calculation	
Input Data			
[9]	Bundled Load Served by IOU Power (MWH)	Supplied by IOU	50,000,000
[11]	Bundled Load Served by DWR Power (MWH)	DWR Revenue Requirement	15,000,000
[13]	Average Cost of Old World IOU Power ($/MWH)	Supplied by IOU	$85.00
[15]	Average Cost of DWR Power ($/MWH)	DWR Revenue Requirement	$90.00
[17]	DA DWR Power Charge Migrating Load After 2.1.01 (MWH)	Supplied by IOU	12,000,000
[19]	DA DWR Power Charge Migrating Load After 7.1.01 (MWH)	Supplied by IOU	11,000,000
[21]	DA Non-Exempt CTC Migrating Load (MWH)	Supplied by IOU	12,500,000
[23]	DL DWR Power Charge Non-Exempt Migrating Load (MWH)	Supplied by IOU	80,000
[25]	DL CTC Non-Exempt Migrating Load (MWH)	Supplied by IOU	85,000
[27]	Market Price Benchmark ($/MWH)		
[28]	Spot Market Purchases/Sales	Supplied by IOU	$50.00
[29]	ERRA	CPUC Proceeding	$60.00
[30]	Forecasted 1-Year Energy Prices	Energy Commission	$65.00
[32]	Line Losses (%)	Supplied by IOU	8.00%
[34]	CTC Accrual Rate	IOU ERRA	$12.00
[35]	New World Procurement Accrual Rate	IOU ERRA	$5.00
DWR Power Charge Accrual Rate (Total Portfolio Methodology)			
[40]	Average Cost of Old World Bundled Portfolio ($/MWH)	(([9]*[13])+([11]*[15]))/([9]+[11])	$86.15
[41]	Market Price Benchmark Adjusted for Line Losses ($/MWH)	[30] X (1+[32])	70.20
[42]	Above-Market Old World Bundled Portfolio Costs ($/MWH)	[40] - [41]	$15.95
[44]	Bundled Load (MWH)	[9] + [11]	65,000,000
[45]	Above-Market Old World Bundled Load Portfolio Costs ($)	[42] X [44]	$ 1,037,000,000
[47]	Above-Market Old World Bundled Load Portfolio Costs Allocated to ($):		
[48]	Bundled Load	(([9]+[11]) X [45])/([9]+[11]+[19]+[23])	$ 885,975,289
[49]	DA Load	([19] X [45])/([9]+[11]+[19]+[23])	149,934,280
[50]	DL Load	([23] X [45])/([9]+[11]+[19]+[23])	1,090,431
[51]	Total	[48] + [49] + [50]	$ 1,037,000,000
[53]	DA Indifference Rate ($/MWH)	[49] / [17]	$12.49
[54]	ERRA CTC Accrual Rate ($/MWH)	[34]	(12.00)
[55]	DA DWR Power Charge Accrual Rate ($/MWH)	[53] - [54]	$0.49
[57]	DL Indifference Rate ($/MWH)	[50] / [23]	$13.63
[58]	ERRA CTC Accrual Rate ($/MWH)	[34]	(12.00)
[59]	DL DWR Power Charge Accrual Rate ($/MWH)	[57] - [58]	$1.63

Appendix 1C
Total Portfolio Adjustment
DL Recommendation

Row	Description	Calculation	
Input Data			
[9]	Bundled Load Served by IOU Power (MWH)	Supplied by IOU	50,000,000
[11]	Bundled Load Served by DWR Power (MWH)	DWR Revenue Requirement	15,000,000
[13]	Average Cost of Old World IOU Power ($/MWH)	Supplied by IOU	$85.00
[15]	Average Cost of DWR Power ($/MWH)	DWR Revenue Requirement	$90.00
[17]	DA DWR Power Charge Migrating Load After 2.1.01 (MWH)	Supplied by IOU	12,000,000
[19]	DA DWR Power Charge Migrating Load After 7.1.01 (MWH)	Supplied by IOU	11,000,000
[21]	DA Non-Exempt CTC Migrating Load (MWH)	Supplied by IOU	12,500,000
[23]	DL DWR Power Charge Non-Exempt Migrating Load (MWH)	Supplied by IOU	80,000
[25]	DL CTC Non-Exempt Migrating Load (MWH)	Supplied by IOU	85,000
[27]	Market Price Benchmark ($/MWH)		
[28]	Spot Market Purchases/Sales	Supplied by IOU	$50.00
[29]	ERRA	CPUC Proceeding	$60.00
[30]	Forecasted 1-Year Energy Prices + Capacity Adder	CPUC Energy Division	$65.00
[32]	Line Losses (%)	Supplied by IOU	8.00%
[34]	CTC Accrual Rate	IOU ERRA	$12.00
[35]	New World Procurement Accrual Rate	IOU ERRA	$5.00
CTC Accrual Rate (Total Portfolio Methodology)			
[39]	Average Cost of Old World IOU Power ($/MWH)	[13]	$85.00
[40]	Market Price Benchmark Adjusted for Line Losses ($/MWH)	[30] X (1+[32])	70.20
[41]	Above-Market IOU Old World Portfolio Costs ($/MWH)	[39] - [40]	$14.80
[43]	Bundled Load Served by IOU Power (MWH)	[9]	50,000,000
[44]	Above-Market IOU Old World Portfolio Costs ($)	[41] X [43]	$ 740,000,000
[46]	Above-Market IOU Old World Portfolio Costs Allocated to ($):		
[47]	Bundled Load	(([9]+[11]) X [44]))/([9]+[11]+[21]+[25])	$ 619,965,199
[48]	DA Load	([21] X [44])/([9]+[11]+[21]+[25])	119,224,077
[49]	DL Load	([25] X [44])/([9]+[11]+[21]+[25])	810,724
[50]	Total	[47] + [48] + [49]	$ 740,000,000
[52]	DA CTC Accrual Rate ($/MWH)	[48] / [21]	$9.54
[54]	DL CTC Accrual Rate ($/MWH)	[49] / [25]	$9.54
Total Portfolio Adjustment ($/MWH)			
[58]	DA Load	[52] - [34]	($2.46)
[59]	DL Load	[54] - [32]	($2.46)

Note: The Total Portfolio Adjustment, shown above, would also be applied to non-bundled customers exempt from the DWR Power Charge and subject to CTC.

Appendix B

Proposals for Capacity/Resource Adequacy Adders

1. Average Combustion Turbine Cost (CLECA, CMTA, AReM)

The capacity/resource adequacy adder would equal the annual carrying cost of a combustion turbine, as reported in the CEC's *Comparative Cost of California Central Station Electricity Generation Technologies*,(June 2003, CEC report 100-003-01), Appendix D, adjusted for inflation. Using the Bureau of Economic Analysis' implicit price deflator for gross domestic product (as reported in the EIA's *Annual Energy Outlook* Table 1.1.9), the 2005 capacity/resource adequacy adder would equal $9.44/MWh.

2. PG&E Combustion Turbine Cost Net of Energy Use (PG&E)

PG&E proposes to use the As-delivered Capacity/resource adequacy value determined by the Commission for each utility converted to a $/MWh value by dividing by the appropriate number of hours. This issue is currently being addressed in the Commission's Avoided Cost Proceeding R.04-04-025. Such an adder will recognize the cost of complying with resource adequacy requirements.

For illustration purposes, PG&E calculates its proposed capacity/resource adequacy price using 2004 NP-15 day ahead prices and Citygate gas prices, an existing 300 MW steam unit with the cost and operating parameters described in PG&E's August 31, 2005 filing to the CPUC in Rulemakings No. 04-04-003 and 04-04-025.

The going-forward fixed cost needed to maintain the 300 MW unit in operation during 2004 is $21.76/kw-yr. (PG&E has estimated this cost to be about $22.60/kw-yr in 2006-2007.) The net energy benefits received by PG&E customers, as calculated by PG&E in the above-referenced proceeding, is $11.34 for 2004. Therefore PG&E's net cost for capacity/resource adequacy would be $10.42/kw-yr. Dividing the $10.42/kw-yr by 8760 hours per year results in a value of $1.20 per MWh. In the absence of an estimate of net energy benefits received by PG&E customers in 2006-2007, this capacity/resource adequacy value is assumed to apply in those years.

For illustrative purposes, below are approximate values for 2006 and 2007 (these values are not adjusted to the customer meter).

Year	Average CT ($/MWh)	PG&E CT (net energy) ($/MWh)
2006	9.6	1.2
2007	9.8	1.2

Appendix C

CRS Data Input Tables, Supporting Calculations and Source Documents for Data

CRS Data Input Source Documents

	Description	Data Source
1	Bundled Load Served by IOU Power (MWH)	Volume of load is determined by IOU in IOU ERRA Proceeding
2	Bundled Load Served by DWR Power	Volume of load is determined by DWR in DWR Revenue Requirement Proceeding
3	Average Cost of IOU Power ($/MWH)	IOU costs of generation and procurement divided by IOU energy deliveries to bundled customers. IOU costs include (1) URG revenue requirement: authorized revenue requirement, fuel costs, franchise fees, uncollectibles; (2) IOU procurement: bilaterals, PPAs, IDs, renewables, QFs, spot purchases, surplus sales, and ISO costs related to energy delivery; (3) other costs including ISO GMC
4	Average Cost of DWR Power ($/MWH)	DWR costs to serve bundled customer (DWR revenue requirement) divided by DWR deliveries to bundled customers. DWR signed numerous long term contracts during the CA energy crisis in 2001 and 2002. These contracts were allocated to customers in each IOU service territory.
5	Volume of DA – Departure Post 2.1.01 (MWH)	DA load that departed bundled service after February 1, 2001 pays the DWR power charge component of the CRS. Volume of load is determined by IOU based on billing records.
6	Volume of DA – Departure Post 7.1.01 (MWH)	DA load that departed bundled service after July 1, 2001 is the volume used to apportion above market costs of the DWR portfolio to direct access. These costs are subsequently spread across load departing bundled service after February 1, 2001. Volume of load is determined by IOU based on billing

		records.
7	Volume of DA Non-Exempt CTC (MWH)	DA volume responsible for paying the IOU's Competition Transition Charge. Volume determined in IOU ERRA proceeding
8	Volume of DL Non-Exempt DWR Power Charge (MWH)	DL volume responsible for paying the DWR power charge. Volume of load is determined by IOU based on billing records in accordance with Commission decisions as to departure date and exemption status. Energy division receives and reviews exemption worksheets.
9	Volume of DL Non-Exempt CTC (MWH)	DL volume responsible for paying the Competition Transition Charge (CTC). Volume determined in IOU ERRA proceeding.
10	Market Price Benchmark	Established using the Commission approved approach. Recommended approach from this report would be determined annually by Energy Commission.
11	Line Losses	Distribution line losses determine annually in ERRA proceeding.

Index to Data Input Tables

Table Appendix C-1 DL Recommended Total Portfolio Adjustment Methodology

PG&E Data Input Tables

1. Using benchmark adopted in D.05-01-040.
2. Using joint parties benchmarks
3. MDL CRS recommended by Working Group

SCE Data Input Tables

1. Using benchmark adopted in D.05-01-040.
2. Using joint parties benchmarks
3. MDL CRS recommended by Working Group

SDG&E Data Input Tables

1. Using benchmark adopted in D.05-01-040.
2. Using joint parties benchmarks
3. MDL CRS recommended by Working Group

Table Appendix C-1

DL RECOMMENDED TOTAL PORTFOLIO ADJUSTMENT METHODOLOGY BELOW

Shows results for Total Portfolio Adjustment using benchmarks and methodology as noted.

Total Portfolio Adjustment (applies to DL that pays CTC but is exempt from DWR Power Charge, $/MWh)

	2004	2005	2006	2007	2008	2009	2010	2011
MDL CRS Accrual Rates Based on Benchmark Adopted in D.05-01-040								
PG&E	3.22	(6.71)	(3.43)	(0.67)	(5.99)	(1.51)	(1.91)	(7.11)
SCE	(1.27)	(6.24)	1.05	2.46	(7.56)	(4.15)	(6.53)	(10.94)
SDG&E	13.45	0.01	(1.71)	(1.54)	(2.00)	2.52	(1.91)	(8.97)
MDL CRS Accrual Rates Based on Benchmark Adopted in D.05-01-040 for 2003-05 and Working Group Recommended Benchmarks 2006-2011								
PG&E	3.22	(6.71)	(21.31)	(15.69)	(10.85)	(9.97)	(4.46)	1.35
SCE	(1.27)	(6.24)	(19.89)	(15.29)	(12.61)	(13.07)	(5.73)	(0.62)
SDG&E	13.45	0.01	(15.35)	(13.81)	(11.58)	(9.96)	(8.27)	(1.75)
MDL CRS Accrual Rates Based on Benchmarks Implied by Working Group Recommended EOY 2005 Balance for 2003-05 and Working Group Recommended Benchmarks for 2006-2011 and Modification to Methodology by Len Viejo								
PG&E	(2.21)	(2.42)	(21.97)	(16.20)	(10.93)	(9.15)	(2.90)	(0.97)
SCE	(4.30)	(10.97)	(22.06)	(17.02)	(12.72)	(10.94)	(6.39)	(4.56)
SDG&E	~~10.62~~	~~1.22~~	~~(10.10)~~	~~(9.60)~~	~~5.11~~	~~5.49~~	~~4.19~~	~~21.88~~

Model Tables Supporting CRS Results Based on Benchmark Adopted in D.05-01-040

PG&E DA/DL/CCA COST RESPONSIBILITY SURCHARGE CALCULATION

Values in US Dollars or GWh

Description	Calculation	2003	2004	2005	2006	2007	2008	2009	2010	2011
Total Responsible Load IOU AMC		79,222,216	80,919,482	82,327,211	82,887,536	81,448,258	82,488,048	83,541,162	84,607,771	85,606,043
Total Responsible Load DWR AMC		78,652,302	79,879,332	81,287,061	81,847,386	80,408,108	81,447,898	82,501,012	83,567,621	84,565,893
Qualifying Bundled Load- IOU AMC		71,223,549	72,225,778	73,633,506	74,193,831	72,754,553	73,794,343	74,847,457	75,914,066	76,912,338
Qualifying Bundled Load- DWR AMC		71,223,549	72,225,778	73,633,506	74,193,831	72,754,553	73,794,343	74,847,457	75,914,066	76,912,338
Qualifying Departing Load- IOU AMC		1	2	3	3	3	3	3	3	3
Qualifying Departing Load- DWR AMC		1	2	3	3	3	3	3	3	3
Qualifying Direct Access Load- IOU AMC		7,998,666	8,693,702	8,693,702	8,693,702	8,693,702	8,693,702	8,693,702	8,693,702	8,693,702
Qualifying Direct Access Load- DWR AMC		7,428,752	7,653,552	7,653,552	7,653,552	7,653,552	7,653,552	7,653,552	7,653,552	7,653,552
Above Market IOU Costs		732,412,612	849,975,495	(128,631,738)	(27,525,840)	197,926,239	(238,365,393)	132,415,485	100,731,460	(343,119,898)
Above Market DWR Costs		950,762,672	826,217,325	247,676,952	351,154,112	328,916,236	79,891,658	242,876,468	761,065,962	517,768,966
Market Price Benchmark @ customer meter				65.35	68.03	63.03	70.97	60.11	61.99	72.07
Line Losses		6%	6%	6%	6%	6%	6%	6%	6%	6%
Market Price Benchmark @ ISO				61.65	64.18	59.47	66.95	56.71	58.48	67.99
Average Bundled Rate		68.71	72.02	66.97	72.40	70.28	68.82	65.13	73.34	74.34
Average Bundled Rate IOU Power		59.65	65.18	62.91	67.52	66.80	66.47	62.59	63.41	67.39
Average Bundled Rate DWR Power		90.47	89.53	77.17	85.33	79.36	74.81	71.48	213.57	213.39
Total Bundled Costs		4,893,833,656	5,201,798,047	4,931,207,488	5,371,298,555	5,112,886,975	5,078,831,336	4,874,687,467	5,567,701,831	5,717,877,317
IOU Bundled Costs		2,998,833,656	3,384,949,190	3,314,247,614	3,639,025,718	3,514,218,129	3,523,349,990	3,347,630,012	4,495,390,262	4,936,042,647
DWR Bundled Costs		1,895,000,000	1,816,848,857	1,616,959,873	1,732,272,836	1,598,668,846	1,555,481,345	1,527,057,455	1,072,311,569	781,834,670
Total Bundled Load		71,223,549	72,225,778	73,633,506	74,193,831	72,754,553	73,794,343	74,847,457	75,914,066	76,912,338
IOU Bundled Load		50,277,087	51,931,636	52,681,365	53,893,280	52,610,770	53,003,083	53,485,102	70,893,157	73,248,425
DWR Bundled Load		20,946,462	20,294,142	20,952,141	20,300,551	20,143,783	20,791,260	21,362,354	5,020,909	3,663,914
Incremental DA Load 7/1/01		7,428,752	7,653,552	7,653,552	7,653,552	7,653,552	7,653,552	7,653,552	7,653,552	7,653,552
Pre-2003 DL Non-exempt Load		-	-							
2003 DL Non-exempt load		1	1	1	1	1	1	1	1	1
2004 DL Non-exempt load			1	1	1	1	1	1	1	1
2005 DL Non-exempt load				1	1	1	1	1	1	1

Model Tables Supporting CRS Results Based on Implied Benchmark for Working Group Recommended EOY 2005 Balance and Recommended Benchmark 2006-2011

PG&E DA/DL/CCA COST RESPONSIBILITY SURCHARGE CALCULATION

Values in US Dollars or GWh

	2003	2004	2005	2006	2007	2008	2009	2010	2011
Total Responsible Load IOU AMC	79,222,216	80,919,482	82,327,211	82,887,536	81,448,258	82,488,048	83,541,162	84,607,771	85,606,043
Total Responsible Load DWR AMC	78,652,302	79,879,332	81,287,061	81,847,386	80,408,108	81,447,898	82,501,012	83,567,621	84,565,893
Qualifying Bundled Load- IOU AMC	71,223,549	72,225,778	73,633,506	74,193,831	72,754,553	73,794,343	74,847,457	75,914,066	76,912,338
Qualifying Bundled Load- DWR AMC	71,223,549	72,225,778	73,633,506	74,193,831	72,754,553	73,794,343	74,847,457	75,914,066	76,912,338
Qualifying Departing Load- IOU AMC	1	2	3	3	3	3	3	3	3
Qualifying Departing Load- DWR AMC	1	2	3	3	3	3	3	3	3
Qualifying Direct Access Load- IOU AMC	7,998,666	8,693,702	8,693,702	8,693,702	8,693,702	8,693,702	8,693,702	8,693,702	8,693,702
Qualifying Direct Access Load- DWR AMC	7,428,752	7,653,552	7,653,552	7,653,552	7,653,552	7,653,552	7,653,552	7,653,552	7,653,552
Above Market IOU Costs	98,891,409	389,573,877	275,628,509	(1,508,991,325)	(1,025,028,105)	(639,553,241)	(574,333,600)	(115,249,247)	381,047,777
Above Market DWR Costs	686,824,791	646,298,945	408,457,100	(206,885,149)	(139,332,495)	(77,480,336)	(39,404,459)	745,769,429	553,992,106
Market Price Benchmark @ customer meter	57.68	57.68	57.68	95.52	86.28	78.54	73.33	65.04	62.19
Line Losses	6%	6%	6%	6%	6%	6%	6%	6%	6%
Market Price Benchmark @ ISO	54.41	54.41	54.41	90.12	81.40	74.10	69.18	61.36	58.67
Average Bundled Rate	68.71	72.02	66.97	72.40	70.28	68.82	65.13	73.34	74.34
Average Bundled Rate IOU Power	59.65	65.18	62.91	67.52	66.80	66.47	62.59	63.41	67.39
Average Bundled Rate DWR Power	90.47	89.53	77.17	85.33	79.36	74.81	71.48	213.57	213.39
Total Bundled Costs	4,893,833,656	5,201,798,047	4,931,207,488	5,371,298,555	5,112,886,975	5,078,831,336	4,874,687,467	5,567,701,831	5,717,877,317
IOU Bundled Costs	2,998,833,656	3,384,949,190	3,314,247,614	3,639,025,718	3,514,218,129	3,523,349,990	3,347,630,012	4,495,390,262	4,936,042,647
DWR Bundled Costs	1,895,000,000	1,816,848,857	1,616,959,873	1,732,272,836	1,598,668,846	1,555,481,345	1,527,057,455	1,072,311,569	781,834,670
Total Bundled Load	71,223,549	72,225,778	73,633,506	74,193,831	72,754,553	73,794,343	74,847,457	75,914,066	76,912,338
IOU Bundled Load	50,277,087	51,931,636	52,681,365	53,893,280	52,610,770	53,003,083	53,485,102	70,893,157	73,248,425
DWR Bundled Load	20,946,462	20,294,142	20,952,141	20,300,551	20,143,783	20,791,260	21,362,354	5,020,909	3,663,914
Incremental DA Load 7/1/01	7,428,752	7,653,552	7,653,552	7,653,552	7,653,552	7,653,552	7,653,552	7,653,552	7,653,552
Pre-2003 DL Non-exempt Load	-	-							
2003 DL Non-exempt load	1	1	1	1	1	1	1	1	1
2004 DL Non-exempt load		1	1	1	1	1	1	1	1
2005 DL Non-exempt load			1	1	1	1	1	1	1

Model Tables Supporting MDL CRS Recommendation
PG&E DA/DL/CCA COST RESPONSIBILITY SURCHARGE CALCULATION
Values in US Dollars or GWh

	2003	2004	2005	2006	2007	2008	2009	2010	2011
Total Responsible Load IOU AMC	79,222,216	80,919,482	82,327,211	82,887,536	81,448,258	82,488,048	83,541,162	84,607,771	85,606,043
Total Responsible Load DWR AMC	78,652,302	79,879,332	81,287,061	81,847,386	80,408,108	81,447,898	82,501,012	83,567,621	84,565,893
Qualifying Bundled Load- IOU AMC	71,223,549	72,225,778	73,633,506	74,193,831	72,754,553	73,794,343	74,847,457	75,914,066	76,912,338
Qualifying Bundled Load- DWR AMC	71,223,549	72,225,778	73,633,506	74,193,831	72,754,553	73,794,343	74,847,457	75,914,066	76,912,338
Qualifying Departing Load- IOU AMC	1	2	3	3	3	3	3	3	3
Qualifying Departing Load- DWR AMC	1	2	3	3	3	3	3	3	3
Qualifying Direct Access Load- IOU AMC	7,998,666	8,693,702	8,693,702	8,693,702	8,693,702	8,693,702	8,693,702	8,693,702	8,693,702
Qualifying Direct Access Load- DWR AMC	7,428,752	7,653,552	7,653,552	7,653,552	7,653,552	7,653,552	7,653,552	7,653,552	7,653,552
Above Market IOU Costs	70,263,433	377,705,112	225,129,069	(1,563,963,713)	(1,067,095,184)	(645,964,938)	(505,081,782)	17,196,096	182,709,003
Above Market DWR Costs	686,824,791	646,298,945	408,457,100	(206,885,149)	(139,332,495)	(77,480,336)	(39,404,459)	745,769,429	553,992,106
Market Price Benchmark @ customer meter	57.68	57.68	57.68	95.52	86.28	78.54	73.33	65.04	62.19
Line Losses	6%	6%	6%	6%	6%	6%	6%	6%	6%
Market Price Benchmark @ ISO	54.41	54.41	54.41	90.12	81.40	74.10	69.18	61.36	58.67
Average Bundled Rate	66.34	64.71	63.24	70.56	68.90	64.29	58.65	53.62	48.82
Average Bundled Rate IOU Power	59.15	66.47	62.29	66.04	65.73	65.31	62.33	65.41	66.26
Average Bundled Rate DWR Power	90.47	89.53	77.17	85.33	79.36	74.81	71.48	213.57	213.39
Total Bundled Costs	4,724,774,721	4,673,571,791	4,656,868,073	5,235,183,519	5,012,779,329	4,744,381,666	4,389,552,206	4,070,559,140	3,754,842,893
IOU Bundled Costs	2,829,774,721	2,856,722,933	3,039,908,200	3,502,910,683	3,414,110,483	3,188,900,320	2,862,494,751	2,998,247,571	2,973,008,223
DWR Bundled Costs	1,895,000,000	1,816,848,857	1,616,959,873	1,732,272,836	1,598,668,846	1,555,481,345	1,527,057,455	1,072,311,569	781,834,670
Total Bundled Load	71,223,549	72,225,778	73,633,506	74,193,831	72,754,553	73,794,343	74,847,457	75,914,066	76,912,338
IOU Bundled Load	50,277,087	51,931,636	52,681,365	53,893,280	52,610,770	53,003,083	53,485,102	70,893,157	73,248,425
DWR Bundled Load	20,946,462	20,294,142	20,952,141	20,300,551	20,143,783	20,791,260	21,362,354	5,020,909	3,663,914
Incremental DA Load 7/1/01	7,428,752	7,653,552	7,653,552	7,653,552	7,653,552	7,653,552	7,653,552	7,653,552	7,653,552
Pre-2003 DL Non-exempt Load	-	-							
2003 DL Non-exempt load	1	1	1	1	1	1	1	1	1
2004 DL Non-exempt load		1	1	1	1	1	1	1	1
2005 DL Non-exempt load			1	1	1	1	1	1	1

Model Tables Supporting CRS Results Based on Benchmark Adopted in D.05-01-040

SCE DA/DL/CCA COST RESPONSIBILITY SURCHARGE CALCULATION

Values in US Dollars or GWh

	2003	2004	2005	2006	2007	2008	2009	2010	2011
Total Responsible Load IOU AMC	81,853,001	84,160,002	83,506,651	87,564,866	89,117,931	91,133,912	92,945,336	94,826,470	96,796,270
Total Responsible Load DWR AMC	81,621,001	83,928,002	83,274,651	87,332,866	88,885,931	90,901,912	92,713,336	94,594,470	96,564,270
Qualifying Bundled Load- IOU AMC	70,617,000	72,965,000	72,311,648	76,369,863	77,922,928	79,938,909	81,750,333	83,631,467	85,601,267
Qualifying Bundled Load- DWR AMC	70,617,000	72,965,000	72,311,648	76,369,863	77,922,928	79,938,909	81,750,333	83,631,467	85,601,267
Qualifying Departing Load- IOU AMC	1	2	3	3	3	3	3	3	3
Qualifying Departing Load- DWR AMC	1	2	3	3	3	3	3	3	3
Qualifying Direct Access Load- IOU AMC	11,236,000	11,195,000	11,195,000	11,195,000	11,195,000	11,195,000	11,195,000	11,195,000	11,195,000
Qualifying Direct Access Load- DWR AMC	11,004,000	10,963,000	10,963,000	10,963,000	10,963,000	10,963,000	10,963,000	10,963,000	10,963,000
Above Market IOU Costs	1,063,407,601	917,316,391	455,165,756	780,665,913	920,463,918	28,036,781	345,450,253	126,938,976	(297,263,796)
Above Market DWR Costs	908,249,585	797,659,026	551,629,670	804,803,509	608,698,468	288,352,341	436,135,959	(284,677,702)	(453,665,682)
Market Price Benchmark @ customer meter			64.82	67.31	63.55	75.24	63.64	69.91	80.28
Line Losses	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%
Market Price Benchmark @ ISO			61.55	63.92	60.35	71.46	60.43	66.39	76.24
Average Bundled Rate	75.48	76.27	78.74	88.07	83.17	79.20	73.20	68.02	71.51
Average Bundled Rate IOU Power	67.25	70.77	73.36	81.37	79.71	75.73	69.45	72.00	75.98
Average Bundled Rate DWR Power	102.25	89.01	93.80	105.97	92.59	88.36	83.12	57.48	52.88
Total Bundled Costs	5,330,114,000	5,564,875,563	5,693,761,785	6,726,130,206	6,481,151,753	6,331,191,168	5,983,829,373	5,688,836,657	6,121,298,410
IOU Bundled Costs	3,632,114,000	3,605,994,000	3,908,511,294	4,519,874,614	4,540,623,983	4,389,155,447	4,123,518,272	4,371,947,071	5,245,838,383
DWR Bundled Costs	1,698,000,000	1,958,881,563	1,785,250,491	2,206,255,592	1,940,527,769	1,942,035,721	1,860,311,102	1,316,889,586	875,460,027
Total Bundled Load	70,617,000	72,965,000	72,311,648	76,369,863	77,922,928	79,938,909	81,750,333	83,631,467	85,601,267
IOU Bundled Load	54,011,217	50,957,000	53,279,048	55,549,834	56,965,686	57,960,855	59,370,220	60,722,086	69,045,523
DWR Bundled Load	16,605,783	22,008,000	19,032,600	20,820,028	20,957,242	21,978,054	22,380,114	22,909,381	16,555,744
Incremental DA Load 7/1/01	11,004,000	10,963,000	10,963,000	10,963,000	10,963,000	10,963,000	10,963,000	10,963,000	10,963,000
Pre-2003 DL Non-exempt Load MDLN	-	-	2,353	2,353	2,353	2,353	2,353	2,353	2,353
2003 DL Non-exempt load MDLN	1	1	1	1	1	1	1	1	1
2004 DL Non-exempt load MDLN		1	1	1	1	1	1	1	1
2005 DL Non-exempt load			1	1	1	1	1	1	1

Model Tables Supporting CRS Results Based on Implied Benchmark for Working Group Recommended EOY 2005 Balance and Recommended Benchmark 2006-2011
SCE DA/DL/CCA COST RESPONSIBILITY SURCHARGE CALCULATION
Values in US Dollars or GWh

	2003	2004	2005	2006	2007	2008	2009	2010	2011
Total Responsible Load IOU AMC	81,853,001	84,160,002	83,506,651	87,564,866	89,117,931	91,133,912	92,945,336	94,826,470	96,796,270
Total Responsible Load DWR AMC	81,621,001	83,928,002	83,274,651	87,332,866	88,885,931	90,901,912	92,713,336	94,594,470	96,564,270
Qualifying Bundled Load- IOU AMC	70,617,000	72,965,000	72,311,648	76,369,863	77,922,928	79,938,909	81,750,333	83,631,467	85,601,267
Qualifying Bundled Load- DWR AMC	70,617,000	72,965,000	72,311,648	76,369,863	77,922,928	79,938,909	81,750,333	83,631,467	85,601,267
Qualifying Departing Load- IOU AMC	1	2	3	3	3	3	3	3	3
Qualifying Departing Load- DWR AMC	1	2	3	3	3	3	3	3	3
Qualifying Direct Access Load- IOU AMC	11,236,000	11,195,000	11,195,000	11,195,000	11,195,000	11,195,000	11,195,000	11,195,000	11,195,000
Qualifying Direct Access Load- DWR AMC	11,004,000	10,963,000	10,963,000	10,963,000	10,963,000	10,963,000	10,963,000	10,963,000	10,963,000
Above Market IOU Costs	877,541,933	905,273,000	498,652,203	(1,052,396,624)	(661,258,911)	(431,715,658)	(482,873,100)	202,783,619	701,358,971
Above Market DWR Costs	851,105,067	792,457,563	567,164,109	117,773,306	26,794,692	114,019,785	123,892,366	(256,062,846)	(214,215,795)
Market Price Benchmark @ customer meter	51.00	53.00	64.00	100.22	91.23	83.10	77.51	68.59	65.76
Line Losses	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%
Market Price Benchmark @ ISO	48.43	50.33	60.78	95.17	86.64	78.91	73.61	65.14	62.45
Average Bundled Rate	75.48	76.27	78.74	88.07	83.17	79.20	73.20	68.02	71.51
Average Bundled Rate IOU Power	67.25	70.77	73.36	81.37	79.71	75.73	69.45	72.00	75.98
Average Bundled Rate DWR Power	102.25	89.01	93.80	105.97	92.59	88.36	83.12	57.48	52.88
Total Bundled Costs	5,330,114,000	5,564,875,563	5,693,761,785	6,726,130,206	6,481,151,753	6,331,191,168	5,983,829,373	5,688,836,657	6,121,298,410
IOU Bundled Costs	3,632,114,000	3,605,994,000	3,908,511,294	4,519,874,614	4,540,623,983	4,389,155,447	4,123,518,272	4,371,947,071	5,245,838,383
DWR Bundled Costs	1,698,000,000	1,958,881,563	1,785,250,491	2,206,255,592	1,940,527,769	1,942,035,721	1,860,311,102	1,316,889,586	875,460,027
Total Bundled Load	70,617,000	72,965,000	72,311,648	76,369,863	77,922,928	79,938,909	81,750,333	83,631,467	85,601,267
IOU Bundled Load	54,011,217	50,957,000	53,279,048	55,549,834	56,965,686	57,960,855	59,370,220	60,722,086	69,045,523
DWR Bundled Load	16,605,783	22,008,000	19,032,600	20,820,028	20,957,242	21,978,054	22,380,114	22,909,381	16,555,744
Incremental DA Load 7/1/01	11,004,000	10,963,000	10,963,000	10,963,000	10,963,000	10,963,000	10,963,000	10,963,000	10,963,000
Pre-2003 DL Non-exempt Load MDLN	-	-	2,353	2,353	2,353	2,353	2,353	2,353	2,353
2003 DL Non-exempt load MDLN	1	1	1	1	1	1	1	1	1
2004 DL Non-exempt load MDLN		1	1	1	1	1	1	1	1
2005 DL Non-exempt load			1	1	1	1	1	1	1

Model Tables Supporting MDL CRS Recommendation
SCE DA/DL/CCA COST RESPONSIBILITY SURCHARGE CALCULATION
Values in US Dollars or GWh

	2003	2004	2005	2006	2007	2008	2009	2010	2011
Total Responsible Load IOU AMC	81,853,001	84,160,002	83,506,651	87,564,866	89,117,931	91,133,912	92,945,336	94,826,470	96,796,270
Total Responsible Load DWR AMC	81,621,001	83,928,002	83,274,651	87,332,866	88,885,931	90,901,912	92,713,336	94,594,470	96,564,270
Qualifying Bundled Load- IOU AMC	70,617,000	72,965,000	72,311,648	76,369,863	77,922,928	79,938,909	81,750,333	83,631,467	85,601,267
Qualifying Bundled Load- DWR AMC	70,617,000	72,965,000	72,311,648	76,369,863	77,922,928	79,938,909	81,750,333	83,631,467	85,601,267
Qualifying Departing Load- IOU AMC	1	2	3	3	3	3	3	3	3
Qualifying Departing Load- DWR AMC	1	2	3	3	3	3	3	3	3
Qualifying Direct Access Load- IOU AMC	11,236,000	11,195,000	11,195,000	11,195,000	11,195,000	11,195,000	11,195,000	11,195,000	11,195,000
Qualifying Direct Access Load- DWR AMC	11,004,000	10,963,000	10,963,000	10,963,000	10,963,000	10,963,000	10,963,000	10,963,000	10,963,000
Above Market IOU Costs	636,374,094	649,752,705	60,132,984	(1,242,938,154)	(815,585,610)	(441,569,427)	(285,088,976)	140,398,436	320,385,963
Above Market DWR Costs	806,219,636	730,637,091	502,605,531	117,773,306	26,794,692	114,019,785	123,892,366	(256,062,846)	(214,215,795)
Market Price Benchmark @ customer meter	53.70	55.81	67.39	100.22	91.23	83.10	77.51	68.59	65.76
Line Losses	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%
Market Price Benchmark @ ISO	51.00	53.00	64.00	95.17	86.64	78.91	73.61	65.14	62.45
Average Bundled Rate	77.30	80.16	82.92	87.64	81.09	66.89	58.60	51.29	45.50
Average Bundled Rate IOU Power	64.64	67.00	68.37	78.55	76.98	73.63	70.71	72.06	73.63
Average Bundled Rate DWR Power	102.25	89.01	93.80	105.97	92.59	88.36	83.12	57.48	52.88
Total Bundled Costs	5,458,829,691	5,849,121,903	5,996,198,405	6,693,420,173	6,319,122,348	5,347,395,706	4,790,436,519	4,289,210,392	3,894,488,410
IOU Bundled Costs	3,760,829,691	3,890,240,340	4,210,947,915	4,487,164,581	4,378,594,579	3,405,359,985	2,930,125,418	2,972,320,806	3,019,028,383
DWR Bundled Costs	1,698,000,000	1,958,881,563	1,785,250,491	2,206,255,592	1,940,527,769	1,942,035,721	1,860,311,102	1,316,889,586	875,460,027
Total Bundled Load	70,617,000	72,965,000	72,311,648	76,369,863	77,922,928	79,938,909	81,750,333	83,631,467	85,601,267
IOU Bundled Load	54,011,217	50,957,000	53,279,048	55,549,834	56,965,686	57,960,855	59,370,220	60,722,086	69,045,523
DWR Bundled Load	16,605,783	22,008,000	19,032,600	20,820,028	20,957,242	21,978,054	22,380,114	22,909,381	16,555,744
Incremental DA Load 7/1/01	11,004,000	10,963,000	10,963,000	10,963,000	10,963,000	10,963,000	10,963,000	10,963,000	10,963,000
Pre-2003 DL Non-exempt Load MDLN	-	-	2,353	2,353	2,353	2,353	2,353	2,353	2,353
2003 DL Non-exempt load MDLN	1	1	1	1	1	1	1	1	1
2004 DL Non-exempt load MDLN		1	1	1	1	1	1	1	1
2005 DL Non-exempt load			1	1	1	1	1	1	1

Model Tables Supporting CRS Results Based on Benchmark Adopted in D.05-01-040
SDG&E DA/DL/CCA COST RESPONSIBILITY SURCHARGE CALCULATION
Values in US Dollars or GWh

	2003	2004	2005	2006	2007	2008	2009	2010	2011
Total Responsible Load IOU AMC	17,195,695	17,744,152	18,080,659	18,335,519	18,671,693	19,161,356	19,525,438	19,895,936	20,272,963
Total Responsible Load DWR AMC	15,828,225	16,626,499	16,963,006	17,217,866	17,554,041	18,043,703	18,407,786	18,778,284	19,155,310
Qualifying Bundled Load- IOU AMC	15,043,865	15,811,591	16,148,097	16,402,957	16,739,131	17,228,794	17,592,876	17,963,374	18,340,401
Qualifying Bundled Load- DWR AMC	15,043,865	15,811,591	16,148,097	16,402,957	16,739,131	17,228,794	17,592,876	17,963,374	18,340,401
Qualifying Departing Load- IOU AMC	1	2	3	3	3	3	3	3	3
Qualifying Departing Load- DWR AMC	1	2	3	3	3	3	3	3	3
Qualifying Direct Access Load- IOU AMC	2,151,830	1,932,559	1,932,559	1,932,559	1,932,559	1,932,559	1,932,559	1,932,559	1,932,559
Qualifying Direct Access Load- DWR AMC	784,359	814,906	814,906	814,906	814,906	814,906	814,906	814,906	814,906
Above Market IOU Costs	478,372,774	364,364,948	107,999,527	77,845,712	82,462,750	75,791,358	165,546,543	80,588,700	(60,981,046)
Above Market DWR Costs	216,954,355	256,376,467	26,143,053	36,438,904	107,950,488	260,238,041	261,914,128	121,851,614	80,254,605
Market Price Benchmark @ customer meter			65.56	68.09	63.27	65.54	54.25	56.11	75.39
Line Losses	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%
Market Price Benchmark @ ISO			62.85	65.27	60.65	62.84	52.01	53.79	72.28
Average Bundled Rate	92.07	86.09	73.87	75.06	74.64	85.05	78.55	67.38	76.44
Average Bundled Rate IOU Power	93.46	91.10	78.96	77.80	73.03	72.47	69.56	63.65	71.11
Average Bundled Rate DWR Power	89.29	80.64	68.80	72.43	76.29	106.97	92.91	72.87	95.06
Total Bundled Costs	1,385,134,723	1,361,203,446	1,192,856,718	1,231,129,535	1,249,477,131	1,465,281,292	1,381,910,224	1,210,348,882	1,401,967,883
IOU Bundled Costs			636,543,136	623,846,081	617,127,656	793,298,372	752,436,156	680,559,303	1,014,037,250
DWR Bundled Costs	446,000,000	611,440,571	556,313,582	607,283,453	632,349,474	671,982,920	629,474,068	529,789,579	387,930,633
Total Bundled Load	15,043,865	15,811,591	16,148,097	16,402,957	16,739,131	17,228,794	17,592,876	17,963,374	18,340,401
IOU Bundled Load	10,048,658	8,229,665	8,061,641	8,019,037	8,450,695	10,946,876	10,817,834	10,692,931	14,259,310
DWR Bundled Load	4,995,207	7,581,926	8,086,456	8,383,920	8,288,436	6,281,918	6,775,043	7,270,444	4,081,091
Incremental DA Load 7/1/01	784,359	814,906	814,906	814,906	814,906	814,906	814,906	814,906	814,906
Pre-2003 DL Non-exempt Load [Power Charge Loa	1	1	1	1	1	1	1	1	1
2003 DL Non-exempt load [Power Charge Load]		1	1	1	1	1	1	1	1
2004 DL Non-exempt load [Power Charge Load]			1	1	1	1	1	1	1
2005 DL Non-exempt load									

Model Tables Supporting CRS Results Based on Implied Benchmark for Working Group Recommended EOY 2005 Balance and Recommended Benchmark 2006-2011
SDG&E DA/DL/CCA COST RESPONSIBILITY SURCHARGE CALCULATION
Values in US Dollars or GWh

	2003	2004	2005	2006	2007	2008	2009	2010	2011
Total Responsible Load IOU AMC	17,195,695	17,744,152	18,080,659	18,335,519	18,671,693	19,161,356	19,525,438	19,895,936	20,272,963
Total Responsible Load DWR AMC	15,828,225	16,626,499	16,963,006	17,217,866	17,554,041	18,043,703	18,407,786	18,778,284	19,155,310
Qualifying Bundled Load- IOU AMC	15,043,865	15,811,591	16,148,097	16,402,957	16,739,131	17,228,794	17,592,876	17,963,374	18,340,401
Qualifying Bundled Load- DWR AMC	15,043,865	15,811,591	16,148,097	16,402,957	16,739,131	17,228,794	17,592,876	17,963,374	18,340,401
Qualifying Departing Load- IOU AMC	1	2	3	3	3	3	3	3	3
Qualifying Departing Load- DWR AMC	1	2	3	3	3	3	3	3	3
Qualifying Direct Access Load- IOU AMC	2,151,830	1,932,559	1,932,559	1,932,559	1,932,559	1,932,559	1,932,559	1,932,559	1,932,559
Qualifying Direct Access Load- DWR AMC	784,359	814,906	814,906	814,906	814,906	814,906	814,906	814,906	814,906
Above Market IOU Costs	398,718,368	271,975,897	90,012,836	(172,158,176)	(146,503,019)	(107,701,312)	(78,133,712)	(45,952,523)	85,304,388
Above Market DWR Costs	177,357,998	171,259,155	8,100,996	(224,940,693)	(116,618,987)	154,939,883	109,300,932	35,812,451	122,122,284
Market Price Benchmark @ customer meter	53.78	58.06	67.79	99.26	90.36	82.31	76.78	67.94	65.13
Line Losses	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%
Market Price Benchmark @ ISO	51.56	55.66	64.99	95.16	86.63	78.91	73.61	65.14	62.44
Average Bundled Rate	92.07	86.09	73.87	75.06	74.64	85.05	78.55	67.38	76.44
Average Bundled Rate IOU Power	93.46	91.10	78.96	77.80	73.03	72.47	69.56	63.65	71.11
Average Bundled Rate DWR Power	89.29	80.64	68.80	72.43	76.29	106.97	92.91	72.87	95.06
Total Bundled Costs	1,385,134,723	1,361,203,446	1,192,856,718	1,231,129,535	1,249,477,131	1,465,281,292	1,381,910,224	1,210,348,882	1,401,967,883
IOU Bundled Costs			636,543,136	623,846,081	617,127,656	793,298,372	752,436,156	680,559,303	1,014,037,250
DWR Bundled Costs	446,000,000	611,440,571	556,313,582	607,283,453	632,349,474	671,982,920	629,474,068	529,789,579	387,930,633
Total Bundled Load	15,043,865	15,811,591	16,148,097	16,402,957	16,739,131	17,228,794	17,592,876	17,963,374	18,340,401
IOU Bundled Load	10,048,658	8,229,665	8,061,641	8,019,037	8,450,695	10,946,876	10,817,834	10,692,931	14,259,310
DWR Bundled Load	4,995,207	7,581,926	8,086,456	8,383,920	8,288,436	6,281,918	6,775,043	7,270,444	4,081,091
Incremental DA Load 7/1/01	784,359	814,906	814,906	814,906	814,906	814,906	814,906	814,906	814,906
Pre-2003 DL Non-exempt Load [Power Charge Loa	-	-	-	-	-	-	-	-	-
2003 DL Non-exempt load [Power Charge Load]	1	1	1	1	1	1	1	1	1
2004 DL Non-exempt load [Power Charge Load]		1	1	1	1	1	1	1	1
2005 DL Non-exempt load			1	1	1	1	1	1	1

Model Tables Supporting MDL CRS Recommendation
SDG&E DA/DL/CCA COST RESPONSIBILITY SURCHARGE CALCULATION
Values in US Dollars or GWh

	2003	2004	2005	2006	2007	2008	2009	2010	2011
Total Responsible Load DWR AMC	15,828,225	16,626,499	16,963,006	17,217,866	17,554,041	18,043,703	18,407,786	18,778,284	19,155,310
Qualifying Bundled Load- IOU AMC	15,043,865	15,811,591	16,148,097	16,402,957	16,739,131	17,228,794	17,592,876	17,963,374	18,340,401
Qualifying Bundled Load- DWR AMC	15,043,865	15,811,591	16,148,097	16,402,957	16,739,131	17,228,794	17,592,876	17,963,374	18,340,401
Qualifying Departing Load- IOU AMC	1	2	3	3	3	3	3	3	3
Qualifying Departing Load- DWR AMC	1	2	3	3	3	3	3	3	3
Qualifying Direct Access Load- IOU AMC	2,151,830	1,932,559	1,932,559	1,932,559	1,932,559	1,932,559	1,932,559	1,932,559	1,932,559
Qualifying Direct Access Load- DWR AMC	784,359	814,906	814,906	814,906	814,906	814,906	814,906	814,906	814,906
Above Market IOU Costs	428,946,174	307,340,897	129,749,484	(75,870,751)	(67,942,558)	212,149,872	223,540,187	201,963,963	564,401,132
Above Market DWR Costs	177,357,998	171,259,155	8,100,996	(224,940,693)	(116,618,987)	154,939,883	109,300,932	35,812,451	122,122,284
Market Price Benchmark @ customer meter	53.78	58.06	67.79	99.26	90.36	82.31	76.78	67.94	65.13
Line Losses	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%	4.31%
Market Price Benchmark @ ISO	51.56	55.66	64.99	95.16	86.63	78.91	73.61	65.14	62.44
Average Bundled Rate	82.73	78.65	73.87	75.06	74.64	85.05	78.55	67.38	76.44
Average Bundled Rate IOU Power	116.18	113.00	85.15	88.50	81.40	112.35	109.23	96.61	146.89
Average Bundled Rate DWR Power	89.29	80.64	68.80	72.43	76.29	106.97	92.91	72.87	95.06
Total Bundled Costs	1,244,629,299	1,243,522,051	1,192,856,718	1,231,129,535	1,249,477,131	1,465,281,292	1,381,910,224	1,210,348,882	1,401,967,883
IOU Bundled Costs			636,543,136	623,846,081	617,127,656	793,298,372	752,436,156	680,559,303	1,014,037,250
DWR Bundled Costs	446,000,000	611,440,571	556,313,582	607,283,453	632,349,474	671,982,920	629,474,068	529,789,579	387,930,633
Total Bundled Load	15,043,865	15,811,591	16,148,097	16,402,957	16,739,131	17,228,794	17,592,876	17,963,374	18,340,401
IOU Bundled Load	10,048,658	8,229,665	8,061,641	8,019,037	8,450,695	10,946,876	10,817,834	10,692,931	14,259,310
DWR Bundled Load	4,995,207	7,581,926	8,086,456	8,383,920	8,288,436	6,281,918	6,775,043	7,270,444	4,081,091
Incremental DA Load 7/1/01	784,359	814,906	814,906	814,906	814,906	814,906	814,906	814,906	814,906
Pre-2003 DL Non-exempt Load [Power Charge Load]	-	-	-	-	-	-	-	-	-
2003 DL Non-exempt load [Power Charge Load]	1	1	1	1	1	1	1	1	1
2004 DL Non-exempt load [Power Charge Load]		1	1	1	1	1	1	1	1
2005 DL Non-exempt load			1	1	1	1	1	1	1

Appendix D

Commission Discussion of the Indifference Fee Concept

The Commission set forth the rules governing determination of the DA CRS elements in D.02-11-022. In addition to the DWR bond charge and an element to allow utility recovery from DA customers of power cost undercollections incurred during the energy crisis, the Commission directed the establishment of an "indifference fee", measured in a manner to assure remaining bundled customers that they would be indifferent with respect to the level of their power costs to the shift of certain customer load to DA service in the summer of 2001. Set forth below are several passages from that decision which describe and discuss this indifference fee standard.

> 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. Implementation of the Bond Charge applicable to DA customers will become effective only after any legal challenges of the decision have been exhausted, as explained in the Bond Charge decision.
>
> (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.[26]
>
> (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

[26] 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 et al. proceedings.

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.[27] (D.02-11-022, at p. 4.)

* * * * *

We also find that the proper approach to computing customer 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.[28]

The total portfolio approach to computing bundled customer indifference, as adopted herein, will require the computation of two charge 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. (D.02-11-022 at pp. 24-25.)

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[27] In addition, DA customers in the SCE service territory currently pay a "Historic Procurement Charge" to SCE pursuant to D.02-07-032.

[28] The total portfolio approach we adopt, involving the netting of high-cost URG against low-cost sources of power, is intended only for the express purpose of computing bundled ratepayer indifference during the period that DWR-related costs are being paid for through a DA CRS. Nothing in this order should be construed as creating any claim on low-cost URG by DA customers beyond the period covered by the DA CRS into perpetuity.

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.29 This particular DA 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. (D.02-11-022 at p. 27.)

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

Appendix E

DA CRS Undercollection Determinations and Related Implementation Procedures

I. Past Period DA CRS Undercollection Balances

- One of the tasks assigned to the DA CRS Working Group by ALJ Pulsifer was to determine the end of year DA CRS undercollection balances for each utility for each of the years 2003, 2004, and 2005. The ALJ also asked the parties to confirm whether the current methodology for development of the DA CRS should continue to be utilized for the purpose of determining past period undercollection balances and for future year CRS obligations. The Working Group has identified several problems with the current method and the DA Agreement Parties, which include PG&E, SCE, TURN, ORA, CLECA, CMTA and AReM, have agreed on a new approach for prospective application. The DA Agreement Parties have also reached agreement on end of year 2005 DA CRS undercollection balances for PG&E and SCE, which agreement represents a compromise of their differing views on the appropriate figures for 2003, 2004 and 2005.
- Further, the parties have found that the current approach to the calculation of the CRS Indifference Rate has proven cumbersome, administratively difficult and slow to provide both predictions of the Indifference Rate and after the fact verification of such fee. The DA Agreement Parties favor simplification of this process.
- The DA Agreement Parties also agree that the Indifference Rate charged DA customers for the years 2003, 2004 and 2005 should reflect the costs for power that each utility would have incurred had it been required to serve all DA load as bundled. Only by reflecting such cost levels can one determine an Indifference Rate that accurately reflects the need to assure bundled customers that they are no worse off, and no better off, than if DA customers remained on bundled service.
- The DA customer parties, comprised of AReM, CLECA and CMTA, have asserted that the current approach of basing the indifference determination solely on the costs of spot market purchases and sales of surplus power understates the costs that would have been incurred had approximately 13% of total utility load been served, not by ESPs, but by the utilities. These parties contend that a better estimate of the costs that would have been incurred to serve DA load necessarily requires calculation of firm power costs and some level of capacity charges. The DA customer parties developed two approaches to estimating such benchmark prices for each of the years 2003 – 2005. One approach was based on the cost of a one-year strip of power (as assessed late in the year immediately preceding the year in question), plus a capacity cost adder (based on the annual capital costs associated with a

combustion turbine generator). The benchmarks thus determined are $51.6/MWh in 2003, $55.7/MWh for 2004 and $65/MWh for 2005. A second approach was based on one-year forward prices for natural gas at Henry Hub, converted to electricity prices using the methodology adopted for calculating the Market Price Referent. The benchmarks estimated in this fashion were $55.5/MWh in 2003, $60/MWh for 2004 and $66.4/MWh for 2005,

- It is important to note that the DA user parties also argued that in a year in which the indifference fee is a negative figure, this fact should work as a credit against the existing undercollection balance. Other parties disagreed with this use of negative indifference fee amounts for the periods in question.
- Applying the DA users' proposed benchmarks and indifference fee methodology, calculation resulted in estimates of the EOY 2005 undercollection balance as low as *negative* $140 million for PG&E and a positive balance of $357 million for SCE.
- Other parties, including particularly TURN and ORA, disagreed with the DA customer parties' approach to benchmarks as applied to past periods, and particularly with respect to its application to PG&E. TURN argued for application of the existing spot purchase and sales price benchmarks for the period 2003-2005. The result of this approach was EOY 2005 undercollection balances of $156 million for PG&E and $552 million for SCE. Thus, the parties' positions produced a range of potential EOY 2005 undercollection balances of nearly $300 million for PG&E and $200 million for SCE.
- PG&E and SCE proposed benchmarks that would place the EOY 2005 undercollection balances somewhere in between this range. Each utility acknowledged that some amount of capacity-related cost over and above the cost of spot purchases and sales should be included in the benchmark (at least in some of the years under consideration), but they did not agree with the DA customer parties as to the amount of such cost.
- It is important to recognize that the benchmark figures are, in essence, hypothetical numbers in that they represent the estimated cost of power that the utilities would have had to procure if they had served all of the DA load. The DA Agreement Parties recognized that it would be difficult and time-consuming to litigate the merits of their different approaches to the development of these hypothetical benchmark cost figures. In light of their desire to reach a timely resolution of the matter, the DA Agreement Parties simply reached a compromise agreement as to the EOY 2005 undercollection balances for each of the two utilities. While the parties are unable to specify with certainty what the appropriate benchmark cost was for the historic periods, and while they disagree as to the precise amount of capacity costs that would have been incurred for the historic period, they have arrived at an agreement as to the end of year ("EOY") 2005 DA CRS undercollection balances. As discussed below, the settled EOY 2005 DA CRS balances are in the middle of the range of values proposed, on one hand, by the DA customer parties and, on the other, by TURN and ORA. The settlement values also are in the range of balances calculated by PG&E and SCE.

A. Pacific Gas & Electric Company

- The PG&E parties' estimates of the appropriate benchmark cost levels for each of 2003, 2004 and 2005 differ. The parties' estimates of benchmarks for these years result in a range of estimates for the EOY 2005 CRS undercollection balance, from a low of negative $140 million (the Market Price Referent ("MPR") approach with negative indifference, one of two approaches offered by CMTA, CLECA and AReM) to a high of $156 million (the current spot purchase and sales price approach utilized by Navigant Consulting), a spread of nearly $300 million.
- The parties also recognize that there exists an undercollection balance of $30 million for bond charge recovery as of the end of 2005, which will need to be recovered from DA customers.
- Although no consensus was reached on benchmark power costs for past periods, the parties nevertheless agree that given the range and nature of the CRS undercollection balance figures discussed above (including the underlying cost benchmarks driving such figures) and in order to provide all parties with some degree of certainty and finality for these past periods, a reasonable figure for the PG&E end of year 2005 DA CRS undercollection balance, including the bond charge undercollection balance, is $60 million. Further, the parties agree that given the agreed upon approach to calculation of the Indifference Rate for 2006 (as described below), such balance can reasonably be expected to reach zero on June 30, 2006. For purposes of this report, the parties agree that the DA CRS undercollection balance will reach zero on June 30, 2006, and that further specific accounting of the balance is not necessary.
- The DA CRS undercollection will therefore be deemed to be repaid on June 30, 2006 for all DA customers except those that switched to bundled service before that date.

B. Southern California Edison Company

- The SCE parties' estimates of the appropriate benchmark cost levels for each of 2003, 2004 and 2005 differ. The parties' estimates of benchmarks for these years result in a range of estimates for the EOY 2005 CRS undercollection balance, from a low of $357 million (the Market Price Referent ("MPR") approach with negative indifference offered by CMTA, CLECA and AReM) to a high of $552 million (the current spot purchase and sales price approach utilized by Navigant Consulting), a spread of nearly $200 million. However, in recognition of their differences and in an effort to compromise those differences, the SCE parties agree that a reasonable measure of the power price that would have been incurred by SCE to serve its entire DA load for the

years 2003, 2004 and 2005 are $51/MWH, $53/MWH and $64/MWH respectively.[30]

- The parties agree that the DA CRS undercollection balance associated with these benchmarks will be $522 million as of EOY 2005. In addition, the parties agree that there exists a $55 million DWR bond charge undercollection as of the end of 2005, which must be recovered from DA customers.
- The parties conclude, based on their agreed approach to calculation of the Indifference Rate for prospective periods (as described below) that DA customers will begin repaying the CRS undercollection balance in 2006 and that such repayment will accelerate in late 2006 with the end of the one cent Historic Procurement Charge ("HPC"). The parties currently estimate that full repayment of the undercollection balance will be achieved before the end of 2008.

II. Going Forward Calculation of the CRS

- The parties agree that the method for calculation of the Indifference Rate going forward should be modified from the existing method. The benchmark power cost for purposes of determining the Indifference Rate for 2006 should be comprised of the average of cost quotes for one-year strips of power taken during the period November 15 through December 15 and a Resource Adequacy / generation capacity ("RA/Capacity") cost adder. For years following 2006, the cost quotes for one-year strips will be gathered for the period October 1 through October 31 in order to facilitate timely filings by the utilities. The power costs will be differentiated as between NP 15 and SP 15, and applied to PG&E and SCE accordingly. The power costs reflect a 6 X 16 product and the price will be multiplied by a factor of 0.87 to convert the power cost to a 7 X 24 product price.
- The parties recognize that there exists a lack of sound information regarding the cost of RA/Capacity and that it is difficult now to predict appropriate levels for this factor for future years. The parties anticipate that the implementation of the Commission's RAR rules will yield additional cost information. For 2006, the parties agree that the RA/Capacity cost adder will be $8/MWH for SCE and $4/MWH for PG&E, which will be added to the average strip price. The parties agree that they will revisit the level of the RA/Capacity cost adders for years after 2006 as more information concerning the cost of generation capacity and/or resource adequacy becomes available.
- For PG&E, the new market benchmark for 2006 will be $90.12/MWH. For SCE, the new market benchmark for 2006 will be $95.17/MWH.
- This benchmark power cost will be compared to the average cost of the utilities' total portfolio, including both URG power and their allocated DWR

[30] The parties have agreed to these benchmark prices for the sole purpose of setting the EOY 2005 DA CRS undercollection and they agree that these benchmark prices are not to be used as precedent in any other Commission proceeding.

power costs, to determine the level of the Indifference Rate for that year. The utilities shall file an advice letter prior to the end of the year or update their testimony in their ERRA proceedings to reflect such Indifference Rate in the CRS adopted for the subsequent year.

- The parties agree the CTC figure adopted in PG&E's ERRA proceeding will be used in conjunction with the Indifference Rate calculation such that the DWR Power Charge component of DA CRS for DA customers not exempt from that charge will be the residual of the Indifference Rate less the CTC. They further agree that the DWR Power Charge component of DA CRS may be a negative number in those instances in which the CTC is larger than the Indifference Rate, so that overall indifference is maintained. The parties also agree that, once the DA CRS undercollection balance is fully paid off, in no event will the overall Indifference Rate be permitted to be a negative number. Further, negative amounts will not be carried forward to a future year. The specific steps required and agreed to for reconciliation of the CTC and the Indifference Rate are set forth in Section III.
- The parties also agree that in the event the statutory approach to CTC calculation is also adopted for SCE, that such CTC figure for SCE will be used in the Indifference Rate calculation in the same manner as for PG&E, with the following exception: In the event the benchmark in a given year exceeds the level of a utility's total portfolio power cost for that year, and to the extent there remains a DA CRS undercollection balance for such utility, the negative Indifference Rate shall be reflected in calculating the accruals to the undercollection balance for such year. In no event shall such a negative Indifference Rate result in any net payment to customers who have left utility service. However, any accumulated negative indifference amount shall continue to be tracked, and shall be applied to any future positive indifference amounts that may accrue in later years of the applicability of the DA CRS.
- SCE will track accruals to the CRS undercollection balance and will file an advice letter in anticipation of such undercollection balance reaching zero to reduce the CRS to the level dictated by the remaining individual CRS elements. Given the parties agreement on the end of year 2005 undercollection balance and the date that the balance will reach zero, PG&E will not be required to track further the undercollection balance.

III. CRS Determination on a Bottoms-Up Basis on and After July 1, 2006

- On July 1, 2006, the DA CRS undercollection balance for PG&E DA customers will be paid down to zero. Thereafter, the 2.7 cent cap will be removed from the CRS and the components of the CRS calculated separately in the following fashion. The DWR Bond Charge, the ECRA rate, and the ongoing CTC will not be changed on July 1, 2006, nor will the basis for the calculation of the Franchise Fee Surcharge currently paid by DA customers.

- The DWR Power Charge component, currently identified separately on direct access non-exempt customers' bills, will be renamed the Power Charge

Indifference Adjustment (PCIA) charge. It will be determined as described below:

- The PCIA charge is to be set to preserve the indifference concept adopted in D. 02-11-022 for those direct access customers who pay the DWR Power Charge component of DA CRS, while accommodating the determination in the ERRA decision that ongoing CTC shall be set for all customers, including DA customers responsible for the DWR Power Charge component of DA CRS, on a "statutory" basis.

- In addition, the PCIA charge is to be set to recover an amount to reflect the franchise fees associated with the DWR revenues collected from direct access customers for the DWR Bond Charge and the DWR Power Charge.

- To accomplish this, the cost responsibility under the sum of the ongoing CTC and the PCIA charge for direct access customers who pay the DWR Power Charge component of DA CRS should equal their responsibility under the Indifference Rate concept, plus an amount to reflect the franchise fees associated with the DWR revenues collected from direct access customers for the DWR Bond Charge and the DWR Power Charge. The direct access non-exempt customers' share of the indifference amount is their proportion of the above market component of the sum of (1) PG&E's 2006 DWR power charge revenue requirement plus (2) PG&E's old world generation. This amount shall be non-negative, and there shall be no carry forward of negative balances.

- The direct access non-exempt customers' responsibility for franchise fees associated with DWR revenue**s** will be determined based on an estimate of DWR Bond Charge and Power Charge revenues paid by these customers, multiplied by the adopted franchise fee factor. No amount for franchise fees associated with DWR revenues will be assessed on direct access customers who pay the DWR bond charge, but do not pay the DWR Power Charge component of the DA CRS.

- The revenue requirement for the PCIA charge is the difference, positive or negative, between direct access non-exempt customers' share of the indifference amount and these customers' share of the ongoing CTC revenue requirement, plus the amount necessary to reflect the franchise fees associated with the DWR revenues collected from direct access customers for the DWR Bond Charge and the DWR Power Charge component of DA CRS.

- Under this approach, the revenues collected from direct access non-exempt customers under the PCIA charge and the ongoing CTC, combined, are equal to these customers' share of the indifference amount, plus these customers responsibility for the franchise fees associated with the DWR revenues collected from them.

- If direct access non-exempt customers' share of the indifference amount exceeds these customers' share of the ongoing CTC revenue requirement, then the difference is these customers' DWR power cost obligation. The PCIA charge is positive, and has the effect of decreasing bundled customers' DWR remittance rate, and therefore, for PG&E only, of decreasing bundled customers' PCCBA rate.

- If direct access non-exempt customers' share of the indifference amount is less than these customers' share of the ongoing CTC revenue requirement, then these customers' DWR power cost obligation is zero. The PCIA charge is negative, and has the effect of increasing bundled customers' ERRA costs (for PG&E) or Utility Retained Generation rates (for SCE). The PCIA charge (including DWR franchise fees) will be set in proportion to the ongoing CTC.

- The 2006 DWR revenue requirement for the determination of the indifference amount shall be the amount adopted in the 2006 DWR revenue requirement decision, D. 05-12-010. The 2006 revenue requirement for old world resources is the amount adopted in the utilities' 2006 ERRA proceedings and/or in the most recent base revenue requirement proceeding[31]. The sales forecast used to determine the direct access non-exempt customers' share of these costs will be the sales forecast presented in the utilities' 2006 ERRA proceedings, as modified in the 2006 AET for PG&E. If the 2006 DWR revenue requirement or utilities' 2006 ERRA/Ongoing CTC revenue requirement is modified, then the calculations described above shall be modified to reflect such changes.

- The market benchmark used to determine the direct access non-exempt customers' share of these costs is $90.12/MWH ($95.52 at the meter) for PG&E and $95.17/MWH ($100.22 at the meter) for SCE in 2006. These benchmarks represent the 30-day average, over the period from November 15, 2005 to December 15, 2005, of 12 month forward prices for 2006 at NP 15 and SP15, respectively, to which is added a "resource adequacy" amount of $4/MWH for PG&E and $8/MWH for SCE. The average PCIA charge for 2006 for PG&E is negative 0.306 cents per kWh and for SCE is negative 1.805 cents per kWh.[32]

IV. Repayment of the DA CRS Undercollection Loan

A. Pacific Gas & Electric

- The DA Agreement Parties agree that, effective January 1, 2006, the implementation of the Phase 2 bundled rates in PG&E's 2003 GRC will remove the undercollection loan element currently reflected in bundled customer rates. Further, the parties estimate that noncore bundled customers have, since implementation of the bankruptcy settlement rates in March 2004, contributed revenues to the CRS undercollection loan which far exceed the maximum level of the CRS undercollection balance, and that this excess payment amount is $325 million, the benefit of which was received by core bundled customers through lower power charges.
- The parties acknowledge that DA customers made repayments toward the CRS undercollection balance through the capped CRS charge in 2005 and that such repayments will continue during the first six months of 2006.

[31] Since the Edison TY 2006 GRC has yet to be decided by the Commission, Edison will file an advice letter to update the DA CRS calculation following the issuance of a final GRC Phase 1 decision if that decision results in a change in the generation revenue requirement of more than 2% from that reflected in the current calculation. A similar 2% update rule shall apply to future changes in the IOUs' generation base revenue requirements.

[32] This negative 1.805 cent figure is expected to be affected by the update calculation referred to in FN 27 should the Commission adopt the ALJ's recommendation with respect to treatment of administrative A&G costs in Edison's TY 2006 GRC.

- Therefore, effective with the anticipated July 1, 2006 advice letter filing, PG&E will adjust bundled customer power charges to reflect the overpayment of the loan by noncore bundled customers in the amount of $325 million. This overpayment amount will be recovered from core bundled service customers and credited against the rates of noncore bundled customers over a 30-month period ending December 31, 2008, using an equivalent annual increase to core bundled customers of $130 million and an equivalent annual decrease to noncore bundled customer of $130 million.
    - On July 1, 2006, January 1, 2007 and January 1, 2008, the increase or decrease will be allocated among customer groups on an equal cents per kWh basis. Rates will be designed by increasing or decreasing energy related (i.e., per kWh) generation rate components by an equal cents per kWh. In the residential class, consistent with current practice, the increase will be allocated by proportional increases to the Tier 3, Tier 4, and Tier 5 surcharges such that the revenue allocated to the residential class is fully collected from the residential class. On January 1, 2009, this differential adjustment to core and noncore bundled rates will be discontinued.

B. Southern California Edison Company

- The DA Agreement Parties agree that SCE's large bundled customers are currently paying an increment in their power rates to fund the CRS undercollection and have been paying such increment since August/September 2003 per the SCE "settlement" rates (D. 03-07-029). SCE estimates that its large bundled customers will have paid a total of $701 million toward funding the CRS undercollection "loan" by end of year 2005, and the parties agree that this amount exceeds the high point of the CRS undercollection balance. Further, the parties agree that large bundled customers have overpaid by $95 million the amount of power rates they would have paid under normal Commission-approved allocation of such costs.

- The parties agree that it is appropriate and necessary to remove this "loan" increment from large bundled customer power rates and that SCE should prepare and file an advice letter, to become effective in the first quarter of 2006, which reduces large bundled customer power rates**.** Further, the parties agree that DA undercollection repayment amounts in 2006 and subsequent years shall be credited to small and large bundled customers in the same proportion as such loan amounts were paid by small and large bundled customers. Further, the $95 million that the large bundled customers overpaid to fund the CRS undercollection loan relative to the maximum level of the DA CRS undercollection shall be reimbursed by small bundled customers following the date on which the CRS undercollection balance reaches zero, over a reasonable amortization period.

- Those DA customers who received DA service during the period the DA CRS undercollection was incurred and have subsequently returned to bundled service are responsible for repayment of a portion of that undercollection. The Undercollection Charge (UC) for these customers will be calculated by subtracting the sum of the DWR Bond Charge, HPC (while it is in effect), the ongoing CTC and the DWR Power Charge component of DA CRS when non-zero, and the negative PCIA charge when the DWR Power charge component of the DA CRS is zero, from the DA CRS cap of 2.7 cents per kWh. The UC will be prorated based on the number of months that such customers received DA service while the DA CRS undercollection was being accumulated.