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Decision 97-12-039 December 3, 1997

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Approval of Valuation and Categorization of Non-Nuclear Generation-Related Sunk Costs Eligible for Recovery in the Competition Transition Charge.	Application 96-08-001 (Filed August 1, 1996)
Application of San Diego Gas & Electric Company to Identify and Value the Sunk Costs of its Non-Nuclear Generation Assets.	Application 96-08-006 (Filed August 1, 1996)
Application of Southern California Edison Company to Identify and Value the Sunk Costs of its Non-Nuclear Generation Assets, in Compliance with Ordering Paragraph No. 25 of D.95-12-063 (as modified by D.96-01-009 and D.96-03-022).	Application 96-08-007 (Filed August 1, 1996)
Application of Pacific Gas and Electric Company To Establish the Competition Transition Charge.	Application 96-08-070 (Filed August 30, 1996)
In the Matter of the Application of Southern California Edison Company to estimate its Transition Costs as of January 1, 1998 in Compliance with Ordering Paragraph 26 of D.95-12-063 (as modified by D.96-01-009 and D.96-03-022), and related changes.	Application 96-08-071 (Filed August 30, 1996)
Application of San Diego Gas & Electric Company to Estimate Transition Costs and to Establish a Transition Cost Balancing Account.	Application 96-08-072 (Filed August 30, 1996)

(See Decision 97-11-074 for appearances.)

FINAL OPINION: TRANSITION COST TARIFF ISSUES

Summary and Background

In this decision, we address various issues related to the pro forma tariffs of Pacific Gas and Electric Company (PG&E), Southern California Edison Company (Edison), and San Diego Gas & Electric Company (SDG&E). The Energy Division has convened several workshops addressing transition cost balancing account pro forma tariffs and tariffs regarding terms and conditions. The most recent round of workshops was held on August 26, 27, and 28, 1997. On September 16, the Energy Division issued its workshop report. On September 25, comments on the workshop report were filed by PG&E, Edison, SDG&E, the Office of Ratepayer Advocates (ORA), jointly by the California Large Consumers Association and California Manufacturers Association (CLECA/CMA), California Industrial Users (CIU), California Farm Bureau (Farm Bureau), Enron, jointly by Cogeneration Association of California and Energy Producers and Users Coalition (CAC/EPUC), Merced Irrigation District (MID), and City of San Diego's Metropolitan Wastewater Department (City of San Diego). On October 9, PG&E requested the opportunity to file reply comments and attached its comments for consideration. The administrative law judge assigned to this proceeding granted PG&E's motion and allowed other parties to file reply comments. On October 24, Edison, SDG&E and MID filed reply comments.

To implement the findings of the Phase 2 Transition Cost Decision (D.97-11-074), we order PG&E, Edison and SDG&E to finalize their transition cost balancing account tariffs by filing compliance advice letters by December 12, 1997. This decision addresses the issues and concerns raised in the workshop process and will allow the utilities to finalize their tariffs. This decision closes these proceedings.

Balancing Account Tariffs: Amortization and Acceleration of Transition Cost Recovery

D.97-06-060, the Phase 1 Transition Cost Decision, ordered PG&E, Edison, and SDG&E to establish transition cost balancing accounts (TCBA) consisting of a Revenue Account and three cost accounts: the Current Cost Account, the Accelerated Cost

Account and the Post-2001 Eligible Costs Account. We established general ratemaking procedures for the recovery of transition costs, including how transition costs would be amortized over the transition period and how to apply revenues greater than current costs, according to the following guidelines which were clarified in D.97-11-074:

1. The recovery of certain costs that are currently incurred may be deferred. The recovery of employee transition costs (as addressed in § 375) may be deferred to the post-2001 period and recovered through December 31, 2006.[1] Section 376 provides that, to the extent that Federal Energy Regulatory Commission (FERC) or Commission-approved recovery of the costs of utility-funded programs to accommodate implementation of direct access, the Power Exchange, and the ISO, reduces the ability of the utilities to collect generation-related transition costs, those generation-related costs may be collected after December 31, 2001, in an amount equal to the implementation costs that are not recovered from the Power Exchange or ISO. Generation-related transition costs which may be displaced by the collection of renewable program funding (as addressed in § 381(d)) may be collected through March 31, 2002. Other than these exceptions, current costs should be recovered as incurred, as required by ratemaking principles and the accounting principle of matching revenues and expenses.

2. Current costs are those cost items eligible for transition cost recovery that are incurred in the current period. The definition of current costs also includes the amortization of depreciable assets on a straight-line basis over the 48-month transition period. In addition, certain regulatory assets which may be jeopardized by write-offs should be amortized ratably over a 48-month period. The specific regulatory assets to which this guideline applies should be determined once Phase 2 eligibility criteria are resolved. The amortization of the investment-related assets should include a provision for associated deferred taxes and the reduced rate of return called for in the Preferred Policy Decision (D.95-12-063, as modified by D.96-01-009).[2] To accommodate ongoing market valuations and accelerated recovery, the utilities

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

[2] We note that D.96-12-083 authorizes Edison to accelerate amortization for Palo Verde on a 60-month period (1997-2001). Each utility's tariffs should conform to specific depreciation periods that may have been adopted for the various nuclear facilities.

should recalibrate recovery levels for remaining months of the schedule, if necessary. To the extent that revenues do not cover costs in a current period, revenues should be applied first to costs incurred during that period and then to scheduled amortization, including that of regulatory assets.

3. To the extent that any additional headroom revenues remain and until such time as plants are depreciated to their anticipated market value, any additional revenues should be applied first to accelerate the depreciation of those transition cost assets with a high rate of return and in a manner which provides the greatest tax benefits. In this way, accelerated recovery of transition costs will benefit shareholders and ratepayers.

4. As assets that are currently included in rate base are amortized, rate base should be reduced correspondingly on a dollar-for-dollar basis, including the impact of associated taxes. This will ensure that the utilities are in compliance with § 368(a), which requires among other things that transition costs be amortized such that the rate of return on uneconomic assets does not exceed the authorized rate of return.

5. As a general guideline for those assets subject to market valuation, generation-related assets should be written down to their estimated market value, but not below, based on a relatively broad estimate of market value. We will be somewhat flexible in applying this guideline. We recognize both PG&E's and Edison's concerns that public disclosure of such estimates could adversely affect the auction process and will address the need for protective orders and confidentiality as the need arises. It is not our intent to revisit the market valuation process occurring in other proceedings.

6. It is the duty of the Commission to determine what transition costs are reasonable and because such costs cannot be determined to be uneconomic or not until we have more information, we reject the utilities' request for complete flexibility in managing their transition cost recovery. We require monthly and annual reports and will institute an annual transition cost proceeding, separate from the Revenue Adjustment Proceeding. In D.96-12-088, we provided that authorized revenues would be established in the respective proceedings for various issue areas and would be consolidated in the Revenue Adjustment Proceeding. In addition, to provide further clarity to this concept, we will require the utilities to revise their pro forma tariffs to indicate that the cost accounts and subaccounts they

establish are <u>not</u> labeled as transition cost subaccounts, but are merely the sunk cost accounts and subaccounts. This is important because we are establishing the sunk costs in Phase 2 of these proceedings, but the uneconomic portion of these costs (which is the portion eligible for transition cost recovery) must be established on an ongoing basis.

7. To the extent feasible, current costs, including those categories that may be deferred, should be recovered before December 31, 2001. We expect that the deferred transition costs should be small relative to the transition costs incurred from qualifying facility (QF) contracts and amortizing nuclear assets. Restructuring implementation costs and employee-related transition costs may be deferred with interest at the usual 90-day commercial paper rate. Generation-related transition costs that are deferred because of funding the programs addressed in § 381(d) shall not accrue interest.

8. To the extent possible, the utilities should manage acceleration of assets to achieve a matching of revenues to current costs plus the portion of noncurrent costs that is accelerated, in a manner to avoid major under- or overcollections of the competition transition charge (CTC). To the extent that noncurrent costs are accelerated, the utilities should recalibrate the remaining months of the recovery schedule to adjust the depreciation schedule through the end of the transition period. To the extent that over- or undercollections occur, interest will accrue at the usual 90-day commercial paper rate, with the exception of deferred generation-related transition costs displaced because of funding the § 381(d) programs.

The workshop participants discussed various approaches to implementing these requirements. PG&E proposes to estimate the market value of each eligible plant and amortize the difference between net book value and estimated market value over the 48-month transition period. The goal is to adjust book value so that net book value and estimated market value are equivalent. If actual market value exceeds the unamortized book value, PG&E would credit the difference to the TCBA and cease further amortization. If unamortized book value is greater than actual market value, PG&E would recognize this loss as a regulatory asset and amortize this amount over the remainder of the transition period. Most workshop participants agreed that it is more convenient to recalibrate amortization and make revenue requirement changes only upon final market valuation than to do so on a prospective basis.

Edison and SDG&E propose similar approaches, but estimate a market value of zero for generation plants in determining the uneconomic portion of the plant to be amortized over the transition period. We prefer PG&E's approach, which is consistent with the guidelines of D.97-06-060. Edison and SDG&E should estimate a market value for each of their generation plants in determining the uneconomic portion to be amortized over the transition period. PG&E, Edison, and SDG&E should adjust amortization schedules and revenue requirements upon final market valuation, and these changes should be reported in the monthly reports and the annual transition cost proceeding. To make such changes more frequently would be cumbersome and would be unlikely to yield substantially more accurate information. We agree with ORA's observation that any continuation of normal non-accelerated depreciation after formal market valuation does not accrue to the transition cost balancing account, but must be recovered either through market revenues or as part of the hydroelectric or geothermal revenue requirement.

Several parties take issue with the idea of accelerating transition cost recovery of QF obligations. It is unlikely that we can forecast with any accuracy the difference between contract prices and the Power Exchange market-clearing price, which could lead to either overcollection or undercollection of such costs. In addition, accelerated recovery of estimated QF contract obligations could delay the end of the rate freeze.

We take this opportunity to clarify guideline 7 of D.97-06-060, which addresses current or actual incurred costs. While current costs may be recovered as incurred, the utilities may not accelerate recovery of post-2001 transition costs, such as those stemming from QF contracts, unless doing so will not jeopardize the possibility that the rate freeze could end prior to March 31, 2002. The utilities may, however, apply revenues to recover those costs associated with QF restructurings, renegotiations, or buy-outs which result in costs incurred during the pre-2002 period.

D.97-06-060 required that regulatory assets which might be jeopardized by write-offs to be amortized ratably over the 48-month transition period and stated that the specific regulatory assets subject to this treatment would be determined after Phase 2 eligibility was resolved. (D.97-06-060, mimeo. at p. 49.) Workshop participants developed a consensus agreement that all regulatory assets should be amortized ratably over the 48-month period and that there is no basis for differentiating among the regulatory assets. We concur with this assessment and clarify guideline 2 accordingly.

Edison has agreed to modify its transition cost balancing account tariff language to respond to ORA's concerns regarding Edison's renewable resource program costs collected under § 381. Edison has agreed to modify its tariff language so that the cumulative debit entries for these programs will equal the credit entries over the transition period and ensure that the statutory amounts delineated in § 381 are not exceeded. We adopt this modification.

The Energy Division has correctly emphasized the need for uniformity and standardization to the extent possible among the utilities' tariffs. We agree that the tariffs should be as user-friendly as possible and that all definitions that are particular to transition cost collection and ratemaking should be uniform among the utilities. We do not insist that the utilities waste time and resources by redefining terms that either are or will be defined in other tariffs. However, we insist that once the transition cost balancing account tariffs and the terms and conditions tariffs are filed in their final forms, all necessary definitions are clearly set forth.

Tracking Transition Cost Obligations for Rate Groups

The Preferred Policy Decision provides explicit guidance on the allocation of transition cost obligations among customers:

> "Transition costs will be allocated to all customer classes using an equal percentage of marginal cost (EPMC) methodology, unless specific circumstances justify a different approach." (Preferred Policy Decision, mimeo. at p. 142.)

Section 367(e)(1) provides that transition costs shall:

> "... be allocated among the various classes of customers, rate schedules, and tariff options to ensure that costs are recovered from these classes, rate schedules, contract rates and tariff options, including self-generation deferral, interruptible, and standby rate options in substantially the same

> proportion as similar costs are recovered as of June 10, 1996, through the regulated retail rates of the relevant electric utility, provided that there shall be a fire wall segregating the recovery of the costs of competition transition charge exemptions such that the costs of competition transition charge exemptions granted to members of the combined class of residential and small commercial customers shall be recovered only from these customers, and the costs of competition transition charge exemptions granted to members of the combined class of customers, other than residential and small commercial customers, shall be recovered only from these customers."

Section 367(e)(3) establishes that the Commission retains existing cost allocation authority, provided that the fire wall and rate freeze principles are not violated. D.96-12-077 ordered PG&E, Edison, and SDG&E to implement interim transition cost balancing accounts to track transition cost obligations and payments for each rate schedule, tariff option and contract. D.97-06-060 recognized the difficulties associated with tracking transition cost obligations at any level more detailed than the rate group level and required PG&E, Edison, and SDG&E to track transition cost obligations and payments at the rate group level. D.97-06-060 acknowledged the parties' assertion that the residual CTC calculation methodology results in one means of allocating transition costs to various customer classes, but did not further address allocation issues, which were left to the cost separation proceeding, Application (A.) 96-12-009 *et al.*

Tracking transition cost obligations was the most controversial issue discussed at the workshops. Edison has included memorandum accounts for this purpose in its pro forma tariffs, but PG&E and SDG&E have not included such accounts in their tariffs. The Energy Division appropriately urged the parties to address concerns that might be important to ensure compliance with § 367(e)(1) and D.97-06-060.

The residual calculation of CTC results in a delinking of transition costs and CTC revenues, i.e., the amount of the CTC residual is not related to actual outstanding transition cost obligations until the total generation-related transition cost obligation is collected and the rate freeze can end. Energy Division explains that this methodology could result in a cost allocation that is not consistent with the cost allocation principles required by § 367(e)(1) and (3), particularly when utilities add new rate options and special discount contracts under § 378. Energy Division also explains that tracking obligations separately may be necessary if the Commission wishes to reflect efficient energy usage by utility service customers under the rate freeze.

New rate options could result in a change in the CTC headroom that would be recovered from customers eligible for the new schedule. The firewall memorandum accounts track only the transition cost revenue shortfalls triggered by customers under CTC exemptions. Thus, transition cost revenue shortfalls or surpluses resulting from new rate schedules would not be restricted to the particular rate group in which the new rate is offered, or even to the appropriate side of the firewall, but instead would be spread among all electricity customers that pay the CTC of a particular utility. In short, the residual calculation of CTC will ensure that costs are recovered in substantially the same proportion from all customers as costs were recovered as of June 10, 1996 only if we were to prohibit creation of tariff options that were not in existence as of that date. Workshop participants agree that this particular problem could be resolved by developing a mechanism to track transition cost revenue shortfalls or surpluses that might arise when new schedules are created. The utilities contend that this problem would be limited to discount rate contracts.

Edison maintains that the cost allocation factors used in its tariffs were included only for tracking purposes and not to determine the end of the rate freeze. Edison does not think that one group's transition obligation should end sooner than any other rate group and states that its EPMC allocation factors are out-dated and useless. PG&E proposes to track the amount of revenue shortfall which may arise from customers' migrating to optional new tariffs and ensure that those amounts do not cross the firewall separations. Edison explains that it could track any transition cost revenue shortfall similar to that proposed in its flexible pricing offer pro forma tariff. CLECA agrees with this proposal. ORA recommends that transition costs should be allocated to rate groups using adjusted EPMC factors. ORA recommends that tracking considerations be handled in the transition cost proceeding, but that allocation factors be handled in the cost separation proceeding.

Attachment E of the workshop report presents parties' proposals for tracking transition cost revenue shortfalls or surpluses that might arise through creation of new rate schedules and the parties' positions on tracking transition cost obligations. PG&E, Edison, SDG&E, Farm Bureau, CIU, CLECA, CAC, and EPUC (sponsoring parties) jointly propose that the residual calculation of CTC is sufficient to ensure proper allocation of CTC obligations, provided any transition cost revenue decreases or increases (revenue differentials) resulting from implementing new optional rate schedules are tracked. The sponsoring parties recommend that a means of tracking revenue differentials resulting from implementation of new rates be established in utility applications to set the new rates.

Farm Bureau notes that "rate group" has not been defined for PG&E and San Diego. PG&E asserts that tracking transition cost obligations presents "intractable problems" because the total amount of transition costs is not known in advance. Edison states that it would be imprudent for the Commission to develop a method for tracking revenue differentials resulting from new rate schedules in a "vacuum," or without having specific proposals for new rate schedules before it. Many of the sponsoring parties indicate that tracking transition cost obligations beyond the level necessary to track revenue differentials resulting from new rate schedules might disrupt the careful balance of interests that was struck in Assembly Bill 1890, however, these concerns relate to allocation issues that are not being addressed in these proceedings.

ORA proposes that transition cost obligations and revenues should be tracked by rate group, and explains that the Phase 1 Decision requires tracking of all transition cost obligations and not only those arising from introduction of new rate schedules. ORA states that it is inclined to prefer allocation of transition cost obligations on a residual basis but that it retains the right to further address allocation concerns. ORA explains that under the residual approach, transition cost payments will equal transition cost obligations only if there are no changes in rate options and customers' usage patterns. ORA also thinks tracking transition cost obligations is necessary to ensure proper allocation of these obligations depending on the outcome of the petition to modify D.97-08-056.

We reject arguments that tracking transition cost obligations by rate group does not comply with § 367(e)(1) and (3). On the contrary, tracking transition cost obligations will ensure that cost shifting does not occur and provides a means by which we can verify the results of the residual CTC calculation methodology to confirm that transition cost allocation principles have been followed. We are not convinced that the sponsoring parties' proposal will ensure that the residual CTC calculation methodology is sufficient to ensure proper allocation of transition cost obligations.

We commend Energy Division staff for clearly articulating and explaining these concepts. In addition to serving as neutral workshop facilitators, advisory staff is obliged to represent the Commission's position, as articulated in various decisions. We are disturbed that a matter of compliance has been opened for further discussion. D.97-06-060 required the utilities to establish mechanisms to track transition cost obligations and payments, and these mechanisms should have been reflected in the pro forma tariffs. We determined that tracking CTC revenues and transition cost recovery at the rate group level, along with the rate unbundling process and the implementation of the fire wall memorandum accounts, would ensure that the requirements of § 367(e)(1) are satisfied. We clarify here that this statement pertains to relaxing the level of disaggregation in which transition cost obligations and payments should be tracked to the rate group level as opposed to the level of each rate schedule, tariff option and contract. We do not find that the residual calculation of the CTC necessarily satisfies cost allocation concerns.

Although participants to the workshop provided valuable suggestions on methods to track any revenue differentials that might result from creation of new rate options, this is not necessary given our commitment to track transition cost obligations at the rate group level. The plain language of § 367(e)(1) states that transition cost obligations should be borne by customers in substantially the same proportion as similar costs were recovered in rates as of June 10, 1996. With the exception of any unique transition cost treatments for discount rate contracts adopted by this Commission, utilities should clearly identify the rate group in which any new proposed schedules would appropriately fit, and any revenue differentials resulting from the new schedules should be restricted to that rate group. We note that D.97-09-047 established that PG&E could discount the distribution component of a customer's bill in implementing new rate schedules, but not the energy, CTC, public purpose benefit charge, or transmission components of the bill. (D.97-09-047, mimeo. at p. 65.)

We do not agree that tracking transition cost obligations requires a prior knowledge of total transition cost obligations. D.97-06-060 ordered a simple accounting methodology in which eligible ongoing transition costs and scheduled depreciation are posted to the current cost account each month, followed by accelerated depreciation if possible. Tracking transition cost obligations is simply a matter of applying allocation factors to the current cost account and accelerated cost accounts each month and then posting each rate group's thus derived transition cost obligation in the memorandum accounts. This method does not require forecasts of total transition costs. While we assumed that issues of transition cost allocation, including transition cost obligation allocation factors, would be considered in the unbundling proceeding, A.96-12-009 *et al.*, that proceeding is now closed. Given our existing cost allocation authority, we may consider transition cost allocation issues in the first Revenue Adjustment Proceeding (RAP)), but at a minimum, we believe that any CTC revenue shortfalls, stemming, for example, from new rate schedules, should be contained on the appropriate side of the firewall.

Edison has proposed memorandum accounts to track transition cost obligations and included these accounts in its pro forma tariffs. We adopt this approach. PG&E and SDG&E shall establish memorandum accounts to track transition cost obligations by rate group, as defined in D.97-06-060. It is crucial that the utilities comply with our orders in establishing their tariffs. PG&E, Edison, and SDG&E were unanimous in stating that transition cost balancing account tariffs and terms and conditions tariffs must be in place by January 1, 1998. Obviously, time is running short and there is little room for inadvertent errors and oversights. PG&E, Edison, and SDG&E shall file compliance advice letters by December 12, 1997, which establish final tariffs implementing the findings of this decision, the Phase 1 transition cost decision (D.97-06-060) and the Phase 2 transition cost decision (D.97-11-074). If the Energy

Division finds the required tariffs to be out of compliance with this order, D.97-06-060, and D.97-11-074, we will have no choice but to require that memorandum accounts be established to track transition cost revenues and costs until each utility's tariff filing can be modified and approved. Pursuant to D.97-11-074, final tariffs must be filed by December 12, 1997. If the tariffs are out of compliance, Energy Division shall immediately inform the utilities by letter and the utilities shall have five days to file advice letters establishing memorandum accounts.

In order to facilitate the process of approving the tariffs, we will shorten the protest period for the compliance advice letters to ten days. This is reasonable, given the many workshops that have been held on the pro forma tariffs and the various iterations of the pro forma tariffs which parties have already seen. In addition, at its discretion, Energy Division may convene a workshop on December 19, 1997 to address any compliance issues which may arise as a result of the utilities' tariff filings. The Energy Division need not file a workshop report.

Termination of the Rate Freeze

We must ensure that we can determine when the rate freeze ends and how to implement the termination of the rate freeze, as we begin the transition period and undertake market valuation of generation assets and acceleration of transition cost recovery. Workshop participants discussed language describing the events that would trigger an end to the rate freeze, and agreed to add language to section J of Edison's balancing account tariffs to reflect this agreement.

We do not agree that this language necessarily reflects the appropriate starting point to identify when the rate freeze should be terminated. As we move through the transition period and gain more familiarity with market conditions, acceleration of transition cost recovery, market valuation, and tracking transition cost obligations, we intend to closely scrutinize the appropriate timing for termination of the rate freeze and appropriate mechanisms for implementing the end of the rate freeze. We direct PG&E, Edison, and SDG&E to file proposals to address this issue in the applications for 1998 transition cost recovery, which will be filed on June 1, 1998, as discussed in D.97-11-074.

Terms and Conditions Tariffs: Consensus Issues

Several issues regarding terms and conditions tariffs were resolved by consensus at the workshops. First, CAC/EPUC were concerned that actual changes for departing load customers due to the normal course of business should be reflected in customers' load profiles. Second, the utilities agreed to add the phrase "up to June 30, 2000" to the tariffs to clarify transition cost responsibility for certain over-the fence power arrangements entered into after December 20, 1995, to reflect that the transition cost responsibility of these customers ends on June 30, 2000. Third, several tariff changes were proposed to be inclusive of the date, December 20, 1995. Fourth, Edison modified its tariffs to clarify load determination procedures (e.g., third party metering or historical load data) and in terms of metering of incremental self-generation load for purposes of determining transition cost responsibility. Finally, the utilities agreed to clarify the treatment of pre- and post-December 20, 1995 over-the-fence arrangements, to distinguish between affiliated and unaffiliated parties.

SDG&E has revised certain of its proposed Rule 23 in response to the City of San Diego's concerns.

We adopt these consensus recommendations and order PG&E, Edison, and SDG&E to implement these changes, as described in the workshop report.

Terms and conditions: nonconsensus Issues

CAC/EPUC identified three issues related to Edison's and SDG&E's tariffs that must be resolved. First, the pro forma tariffs state that a contract is necessary for the operation of parallel emergency generation equipment. CAC/EPUC prefer PG&E's approach, which does not require a contract. SDG&E now agrees to remove reference to a contract obligation. Edison explains that the contract referenced is the *Momentary Parallel Generation Contract*, versions of which have been in effect for over ten years. This contract allows customers to operate in parallel with Edison's system on a momentary basis for the purpose of testing their auxiliary emergency generators and to switch to such generation when Edison's service is interrupted. CAC/EPUC recommend that notification should be sufficient for safety considerations, but state that imposing a utility contract on customers could serve as a barrier or obstacle for other market service options for generation equipment. It is reasonable that these contracts continue to be required to ensure that the electric grid be maintained on a safe and reliable basis.

Second, parties interpret § 372(a)(1) differently. Section 372 describes various exemptions to CTC. Section 372(a)(1) states, in relevant part, that these costs shall not apply:

> "To load served onsite or under an over the fence arrangement by a nonmobile self-cogeneration or cogeneration facility that was operational on or before December 20, 1995, or by increases in the capacity of such an entity holding an ownership interest in or operating the facility and does not exceed 120 percent of the installed capacity as of December 20, 1995, provided that prior to June 30, 2000, the costs shall apply to over the fence arrangements entered into after December 20, 1995, between unaffiliated parties."

Edison has constructed its tariffs using a literal interpretation of this section. CAC/EPUC recommend that this section must be read in conjunction with the entire statute to fully understand it. Section 371 provides that transition costs shall apply to each customer based on the amount of electricity purchased by that customer, subject to changes in usage occurring in the normal course of business, including "enhancement or increased efficiency of equipment or performance of existing self-cogeneration equipment, replacement of existing cogeneration equipment with new power generation equipment of similar size as described in paragraph (1) of subdivision (a) of Section 372."

CAC/EPUC contend that under § 371, load served by a cogeneration facility will not be subject to CTC, in the normal course of business, if it is due to "enhancement or increased efficiency of equipment or performance of existing self-cogeneration equipment" or "replacement of existing cogeneration equipment with new power generation equipment" that does not exceed 120% of the installed capacity existing as of December 20, 1995. SDG&E agrees that the customer has the right to build additional capacity within the 120% rule.

We must interpret § 372 in light of the statute as a whole. Section 371 provides that CTC shall apply to customers based on their usage and that calculation shall account for the described changes in the "normal course of business." Because § 371(b) refers specifically to § 372(1), a particularly careful reading is in order. Section 372(a)(1) grants exemptions to load served onsite or under an over the fence arrangement by the described self-cogeneration or cogeneration facilities, and the installed capacity operational as of December 20, 1995 may therefore be exceeded by up to 20% without triggering CTC. CTC should not apply to nonmobile self-generation or cogeneration which serves load onsite or under an over the fence arrangement described in § 372(a)(1) in terms of the replacement of existing cogeneration equipment with new equipment up to the 120% of installed capacity as of December 20, 1995 or the installation of new or additional generation equipment or facilities which does not exceed 120% of installed capacity as of December 20, 1995. The CTC shall be levied on any load served by the on-site cogeneration unit or under an over the fence arrangement that exceeds the statutory exemption. The increase in load served is the relevant criteria because it is that load to which the volumetric CTC applies.

Third, Edison and CAC/EPUC dispute the interpretation of § 369, which states:

> "The commission shall establish an effective mechanism that ensures recovery of transition costs referred to in Sections 367, 368, 375, and 376, and subject to the conditions in Sections 371 to 374, inclusive, from all existing and future consumers in the service territory in which the utility provided electricity services as of December 20, 1995; provided, that the costs shall not be recoverable for new customer load or incremental load of an existing customer where the load is being met through a direct transaction and the transaction does not otherwise require the use of transmission or distribution facilities owned by the utility."

The dispute centers on those customers whose new load is served through direct transactions, but who rely on the incumbent utility for standby service. CAC/EPUC agree that the customer would pay CTC based on the amount of standby energy used, but argue that CTC should not apply to new or incremental load. The City of San Diego agrees with this interpretation. Edison argues that such an interpretation violates the Legislature's intent that new or incremental load be exempt only when the utility's transmission or distribution facilities are not used at all. Edison describes two examples that would satisfy this requirement: 1) a customer disconnects from the incumbent utility and connects to a different utility by means of a separate transmission or distribution line; and 2) a customer disconnects from the utility, a new generator serves the customer's new load, and a different utility provides standby service. PG&E agrees with Edison and argues that the language of § 369 is unambiguous, with no exception for partial use.

CAC/EPUC state that the utilities will be the only providers of standby services in the near future and thus this interpretation would effectively eliminate this exemption. Edison argues that customer that engages in a direct transaction to acquire generation for its new or incremental load will <u>not</u> necessarily rely on the Utility Distribution Company (UDC) for standby service. In addition, if a direct access customer's source of power fails, it will be subject to the Independent System Operator's (ISO) imbalance energy charges. Edison explains that new or incremental load served through UDC's system would not be distinguishable from unscheduled standby load for purposes of CTC responsibility. Edison maintains there is no basis to characterize standby and regular service as separate transactions, as CAC/EPUC argue.

We look to each word of the section and the section as a whole in interpreting § 369. If a customer engages in a direct transaction to serve new load or incremental load and that new or incremental load "does not otherwise require the use of transmission or distribution facilities owned by the utility," the exemption applies. If the direct transaction requires the use of transmission or distribution facilities owned by the utility, the § 369 exemption does not apply. Therefore, if the direct transaction requires standby service through the use of transmission or distribution facilities owned by the utility, the exemption does not apply. We will use our knowledge of the principles of ratemaking to clarify what is meant by the obligation to pay CTC in relation to the standby rate. Consistent with § 368(a) and the rate freeze which commenced on January 1, 1997, the CTC is an integral component of utility standby charges, and is nonbypassable. Application of the nonbypassable CTC to standby services is complicated by the fact that load protected by the standby service might also be subject to a CTC for energy.

For instance, a 100 MW cogenerator that was operating as of December 20, 1995 and receiving standby service for the full 100 MW would not pay CTC for the energy it continued to generate, but would continue to pay the fixed frozen standby rate, as well as the frozen standby energy rate if incurred. Thus, even though the customer's energy generation is exempt from CTC, this customer pays CTC for these standby services because it is embedded in the frozen rates. (D.97-08-056, mimeo. at p 37.)

Other questions arise if the customer increases capacity. An example will help to explain these issues. Consider a cogenerator that increased capacity 50% from 100 to 150 MW. In this case, by statute (§ 372(b)), energy produced by the first 20 MW of this capacity increase would not be subject to CTC, but the last 30 MW would. The customer would not pay a CTC for any energy generated by the first 20 MW of capacity, but since the customer must pay frozen standby rates to cover this 20 MW, the customer is paying the implicit CTC. In this way the statutory exemption for the first 20% of the expansion applies only to energy generated by the customer. In this example, we must also consider whether the customer would have to pay CTC on standby service if that service was taken from a non-utility provider. The CTC also applies in this case because it is a nonbypassable charge.

Now let us consider the last 30 MW of the cogenerator's capacity expansion in our example. This portion of the expansion is not covered by a statutory CTC exemption, so energy produced by this 30 MW of capacity is subject to the CTC. Standby service procured to cover this 30 MW is also subject to CTC in a manner identical to the discussion of the standby service CTC for the first 20 MW of capacity expansion above. PG&E, Edison, and SDG&E should clarify their tariffs accordingly.

MID is concerned that PG&E's tariffs do not address the right of a customer that selects direct access from an energy service provider that is not exempt from CTC, but then selects a provider that can offer this exemption. PG&E and MID now agree on the language to be included in PG&E's tariffs. PG&E should amend its tariffs to create Subparagraph XX.4.B(1) (Customers Claiming An Exemption Upon Departure) to

Paragraph XX.4.B of its Preliminary Statement. Paragraph XX.4.B(1) should use the current text of Paragraph XX.4.B. We modify the proposed language of subparagraph XX.4.B.(2) in terms of dispute resolution. If PG&E and the customer cannot resolve issues regarding the claim for exemption, they should seek informal dispute resolution from the Energy Division or request mediation assistance from the Administrative Law Judge Division. If these alternative dispute resolution attempts are not successful, the customer should file a complaint at the Commission. Filing a complaint is less onerous than serving a motion on the numerous parties to the electric restructuring rulemaking. PG&E should modify Subparagraph XX.4.B(2) accordingly.

We appreciate PG&E's and MID's concerns regarding dispute resolution procedures that are not consistent, as outlined in D.97-06-060 and this decision. Because we plan on closing the electric restructuring rulemaking in the near future, we prefer that a complaint process with informal dispute resolution be applied to any dispute concerning a claim of CTC exemption, whether the claim is submitted before or after customer departure. In addition, we will require that if the dispute is not resolved by informal dispute resolution procedures within 60 days of the customer's request to pursue informal dispute resolution, the customer may file a complaint. We acknowledge PG&E's and MID's concerns regarding timely resolution of these matters, but allowing 60 days for informal dispute resolution rather than 30 is more pragmatic. With these modifications, we approve the language jointly submitted by PG&E and MID regarding dispute resolution. PG&E should modify its final tariffs accordingly.

The City of San Diego recommends that SDG&E modify its tariffs to reflect the definition of departing load as that of a new customer or the incremental load of an existing customer where the load is being met through a direct transaction and the transaction does not otherwise require the use of transmission or distribution facilities owned by the utility. We have reviewed SDG&E's tariffs and conclude that the definition of departing load does not require modification. Section C.2.(i) of SDG&E's tariffs clarifies that CTC does not apply to incremental load that does not otherwise require the use of transmission or distribution facilities owned by the utility.

Transition Cost Forecast and Lump-Sum Penalties

D.97-06-060 adopts a lump-sum penalty methodology for departing load customers which is equal to the forecast net present value of a customer's remaining transition cost obligation. The decision requests that parties collaborate to determine the basis of the forecast for Edison and SDG&E and whether the forecast used in this penalty should be relatively conservative. D.97-06-060 also stated that the forecasts should to be scaled back to reflect the outcome of the Phase 2 transition cost decision in terms of adopted transition costs and cost categories.

The workshop participants agreed that it is reasonable to use a conservative forecast for purposes of implementing the lump-sum penalty mechanism for departing load customers. In Attachment F of the workshop report, Edison and SDG&E provided their own forecasts for use in implementing their lump-sum departing load penalties. ORA recommends that SDG&E's calculation in Section A of Attachment F should include a factor for the nonbypassable public goods costs as does the calculation in Section B. In response, SDG&E submits revised workpapers that are the same as Attachment F in the Workshop Report except for the addition of the public goods component. (See Attachment 1.) We adopt Edison's forecast in Attachment F and SDG&E's revised forecast as the basis for the Edison and SDG&E lump-sum penalties for departing load customers, subject to the adjustment discussed below.

To adjust utility forecasts of net present value transition cost obligations to reflect the findings of the Phase 2 transition cost decision, PG&E suggests that the forecasts used in the penalty mechanism could simply be scaled back by the percentage that the utilities' transition cost eligibility requests might be reduced. We can implement this requirement by determining the percent difference between the utilities' transition cost eligibility requests, presented in Exhibits 114, 115, and 116 for PG&E, Edison, and SDG&E, respectively, and our determinations in Phase 2, and then reducing the original forecast by this same amount. Workshop participants agree that this methodology is reasonable. We concur, and order PG&E, Edison, and SDG&E to include the adjusted forecasts in the compliance tariff filings.

Comments on Proposed Decision

PG&E, Edison, SDG&E, ORA, Enron, Farm Bureau, City of San Diego, and CLECA/CMA/CIU (jointly) filed timely comments on the proposed decision. Edison, PG&E, ORA, and SDG&E filed timely reply comments. We have incorporated these comments as appropriate, which were particularly helpful regarding the technical clarification necessary to implement the Commission's findings.

Findings of Fact

1. PG&E, Edison, and SDG&E should estimate the market value of each eligible fossil plant and amortize the difference between net book value and estimated market value over the 48-month transition period.

2. It is reasonable to adjust book value so that net book value and estimated market value are equivalent.

3. If actual market value exceeds the unamortized book value, PG&E, Edison, and SDG&E should credit the difference to the TCBA and cease further amortization. If unamortized book value is greater than actual market value, PG&E, Edison, and SDG&E should amortize this amount over the remainder of the transition period.

4. PG&E, Edison, and SDG&E should adjust amortization schedules and revenue requirements upon final market valuation.

5. All necessary definitions should be clearly set forth in final forms of the transition cost balancing account tariffs and the terms and conditions tariffs.

6. It is necessary to track transition cost obligations at the rate group level to ensure that there is no cost shifting pursuant to the requirements of § 367(e)(1) and (3).

7. The residual CTC calculation is not sufficient to ensure that allocation of transition cost obligations complies with the requirements of § 367(e)(1) and (3).

8. Tracking rate group obligations does not require a forecast of total transition cost obligations.

9. Effective January 1, 1998, the utilities shall track transition cost obligations by rate group using allocation factors adopted in the utility's most recent general rate case. These transition cost allocation factors may be re-evaluated in the first Revenue

Adjustment Proceeding, but at a minimum, any CTC revenue shortfalls, stemming, for example, from new rate schedules, should be contained on the appropriate side of the firewall.

10. It is reasonable to adopt the consensus recommendations on terms and conditions issues.

11. It is reasonable for the utilities to continue to require contracts for the operation of parallel emergency generation equipment to ensure that the electric grid is maintained on a safe and reliable basis.

12. The fixed frozen standby rate includes an embedded CTC component. The frozen standby energy rate may also be incurred and could lead to CTC for energy generated, if that energy exceeds statutory exemptions.

13. The CTC shall be levied on any load served by the on-site cogeneration unit or under an over the fence arrangement that exceeds the statutory exemption. The increase in load served is the relevant criteria because it is that load to which the volumetric CTC applies.

14. It is reasonable that PG&E amend its tariffs to address the right of a customer that selects direct access from an energy services provider that is not exempt from CTC, but then selects a provider that can offer this exemption.

15. We adopt the forecasts presented in Attachment F to the workshop report as the basis for Edison's and SDG&E's lump-sum penalties for departing load customers, subject to adjustment for the amounts adopted in the Phase 2 decision.

Conclusions of Law

1. Section 376 permits utilities to recover uneconomic generation-related costs beyond the December 31, 2001 deadline set in § 367(a), to the extent the opportunity to recover these costs is reduced by FERC-or Commission-authorized recovery of unreimbursed costs of programs to accommodate implementation of direct access, the Power Exchange and the Independent System Operator.

2. It is not reasonable to allow accelerated recovery of post-2001 transition costs, such as those stemming from QF contracts, unless doing so will not jeopardize the

possibility that the rate freeze could end prior to March 31, 2002. The utilities may, however, apply revenues to recover those costs associated with QF restructurings, renegotiations, or buy-outs which result in costs incurred during the pre-2002 period.

3. Consistent with D.97-06-060, all eligible regulatory assets should be amortized ratably over the 48-month period and there is no basis for differentiating among the regulatory assets.

4. PG&E, Edison, and SDG&E must establish memorandum accounts to track transition cost obligations at the rate group level in compliance with D.97-06-060 and § 367(e)(1). These memorandum accounts will be used to track transition cost obligations and revenues in case compliance issues arise in connection with tariffs to be filed on December 12, 1997 or later.

5. We must closely scrutinize the appropriate timing for termination of the rate freeze and appropriate mechanisms for implementation.

6. Nonmobile self-generation or cogeneration which serves load onsite or under an over the fence arrangement described in § 372(a)(1) should be exempt from CTC applying to the additions or replacement of existing cogeneration equipment with new equipment up to the 120% of installed capacity as of December 20, 1995 or the installation of new or additional generation equipment or facilities that do not exceed 120% of installed capacity as of December 20, 1995.

7. If a direct transaction does not require the use of transmission or distribution facilities owned by the utility, the § 369 exemption continues to apply to the direct transaction for new or incremental load.

8. For purposes of the lump-sum penalty calculation, it is reasonable to adjust utility forecasts of net present value transition cost obligations to reflect the findings of the Phase 2 transition cost decision in determining the percent difference between the utilities' transition cost eligibility requests as presented in Exhibits 114, 115, and 116 for PG&E, Edison, and SDG&E, respectively, and our determinations in Phase 2, and then reducing the original forecast by this same amount.

9. This order should be effective today so that final transition cost balancing account tariffs and terms and conditions tariffs may be effective on January 1, 1998.

FINAL ORDER

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (Edison), and San Diego Gas & Electric Company (SDG&E) shall file compliance advice letters by December 12, 1997, to establish final tariffs implementing the findings of this decision, the Phase 1 Transition Cost Decision (Decision 97-06-060) and the Phase 2 Transition Cost Decision. The protest period shall be shortened to 10 days. The advice letters shall be effective as of January 1, 1998, unless the Energy Division determines that these tariffs are not in compliance with this decision. If the Energy Division determines that the tariffs are not in compliance with these decisions, the Energy Division shall promptly notify PG&E, Edison, and SDG&E by letter of the non-compliance items and the utilities shall file advice letters establishing appropriate memorandum accounts to track transition costs and revenues.

2. PG&E, Edison, and SDG&E shall include proposals which address the appropriate timing for termination of the rate freeze and appropriate mechanisms for implementing the end of the rate freeze in their applications for 1998 transition cost recovery, which shall be filed on June 1, 1998, as discussed in the Phase 2 decision.

3. The Energy Division may, at its discretion, convene an informal workshop on December 19, 1997 to address any compliance issues which may arise as a result of the utilities' tariff filings. The Energy Division need not file a workshop report.

This order is effective today.

Dated December 3, 1997, at San Francisco, California.

P. GREGORY CONLON
President
JESSIE J. KNIGHT, JR.
HENRY M. DUQUE
JOSIAH L. NEEPER
RICHARD A. BILAS
Commissioners

ATTACHMENT 1
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SAN DIEGO GAS & ELECTRIC COMPANY CALCULATION OF FACTOR FOR LUMP SUM PAYMENTS OF CTCs WORKPAPER

A. Derivation of the gross factor to be applied January 1, 1998 in the case where a Demand for a Lump Sum Payment must be made to a Departing Load customer.

1.	$2.21	Billions	Upper range estimate of Present Value of CTCs at 1.5 cent/kWh market clearing price from 1998.
2.	$0.19	Billions	Present Value of Public Goods through 2002
3.	$2.4	Billions	Subtotal
4.	$1.5	Billions	Authorized Electric Department Revenues from Exhibit 111, Table II.1, SDG&E's last Rate Window Filing with rates becoming effective on June 10, 1996.
5.	1.56	factor	The product of 3. Divided by 4.
6.	1.5	gross factor	The rounding of 5. Above to nearest ¼th.

B. Derivation of the gross factor to be applied in 2002 in the case where a Demand for a Lump Sum Payment must be made to a Departing Load customer.

1.	$1.03	Billions	Upper range estimate of Present Value (in 2002 dollars) of CTCs at 1.5 cent/kWh market clearing price post 2001.
2.	$1.03	Billions	An amount equal to 1. above based on the assumption that the nonbypassable public goods and nuclear decommissioning costs will be approximately the same order of magnitude.
3.	$2.06	Billions	The sum of 1. and 2.
4.	$1.54	Billions	Authorized Electric Department Revenues from Exhibit 111, Table II-1, SDG&E's last Rate Window Filing with rates becoming effective on June 10, 1996.
5.	1.34	factor	The product of 3. Divided by 4.
6.	1.25	gross factor	The rounding of 5. above to the nearest ¼th.

ATTACHMENT 1
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C. Factor for 1/1/2002 is B.6 or = 1.25
   Factor for to reduce the monthly values from 1/1/98 to 12/31/2001 by is
   (A.6 - B.6)/48 months = 0.5%

(END ATTACHMENT 1)