ALJ/ANG/gab

Decision 97-06-060 June 11, 1997

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)

INTERIM OPINION

1. Summary

In this decision, we address the Phase 1 transition cost issues, which include the ratemaking issues associated with establishing the Transition Cost Balancing Accounts for Pacific Gas and Electric Company (PG&E), Southern California Edison Company (Edison), and San Diego Gas & Electric Company (SDG&E). In addition, we review a stipulation presented by all parties on market price proxies, and address consensus and nonconsensus recommendations regarding tariff issues related to terms and conditions for exemptions and departing load. Most importantly, we determine that it is not appropriate to allow complete utility discretion in applying revenues to transition costs and discuss how such discretion impacts the risks of transition cost recovery. We make these determinations according to the mandates provided by the new Public Utilities (PU) Code Sections added by Assembly Bill (AB) 1890 (Ch. 854, Stats. 1996), and using the guidance provided by our Preferred Policy Decision[1] in the Electric Restructuring Rulemaking and Investigation (R.94-04-031/I.94-04-032). In this phase, we adopt general guidelines to be applied to the order of acceleration for recovery of transition costs. Specific findings regarding eligibility of costs for transition costs, and appropriate application of rate of return will be addressed in Phase 2.

2. Background and Procedural History

In April 1994, we initiated R.94-04-031/I.94-04-032, a comprehensive rulemaking and investigation into restructuring California's electric services industry and reforming regulation. After months of extensive public comments and participation, we issued our Preferred Policy Decision, which requested and authorized the investor-owned utilities (IOUs) to make the filings necessary at the Federal Energy Regulatory Commission (FERC) to establish an Independent System Operator (ISO) and Power Exchange which would facilitate a competitive generation framework to begin no later than January 1, 1998. In that decision, we also required the IOUs to unbundle the electric service currently provided to retail customers so that customers' direct access to energy service providers could begin simultaneously with the new market structure.

We also recognized that in the transition to the new industry structure, certain utility generation-related capital and operating costs would prove to be uneconomic and would not be recovered through market revenues. We called these uneconomic or stranded assets "transition costs," and stated that those assets that proved to be economic would be netted against those that proved to be uneconomic in the new market structure. As defined in the Preferred Policy Decision, transition costs arise from generation assets, nuclear power plant settlements, power purchase agreements, qualifying facilities (QFs) contracts, and the reasonable capital costs of early retirement or retraining programs for employees. We defined uneconomic capital costs as those occurring when the market value at the time of divestiture, spin off, or appraisal was less than the net book value of the asset, and for ongoing costs, we defined uneconomic costs as those greater than the clearing price provided by the Power Exchange.

The Preferred Policy Decision stated that these costs would be collected through a nonbypassable competition transition charge (CTC), applied to all retail customers, whether they continue to take bundled service from the IOUs or not. We further stated that valuation of transition costs would rely on market mechanisms to the extent possible and would be designed to minimize transition costs. The Preferred Policy Decision called for the utilities to file applications by September 2, 1996 to establish the level of transition costs as of January 1, 1998. The utilities were also directed to file applications to identify and value the "sunk costs" of their non-nuclear generation assets by April 15, 1996. These principles were affirmed in D.96-03-022, the Roadmap Decision, which called for a scoping workshop to determine issues and procedural

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[1] Decision (D.) 95-12-063, as modified by D.96-01-009.

forums to address various issues, including transition costs. The Roadmap Decision also changed the filing date for the applications addressing the valuation of non-nuclear generation assets to August 1, 1996 and the September 2 transition cost application filing date was changed to August 30, 1996.

On May 17, 1996, Commissioner Conlon, as lead assigned Commissioner in this issue area, convened a scoping workshop to consider issues related to establishing the transition cost balancing accounts, establishing the initial transition cost estimates, calculating ongoing transition costs, adopting the methodology for market valuation, establishing the level of transition costs for allocation and ratesetting purposes, setting the QF buyout incentive, and approving terms and conditions and collection of CTC for departing customers.

As a result of that workshop, Commissioner Conlon issued a ruling on June 28, which established that: 1) terms and conditions for exemptions and departing load would be addressed early in these proceedings; 2) QF buyout incentive issues would be addressed in a separate track in electric restructuring; 3) the details of developing the methodology for valuing utility assets that are retained (rather than being divested or spun off) should be developed in a later phase of the transition cost proceedings; and 4) the details of cost allocation and ratesetting related to transition cost recovery should be developed in the unbundling and ratesetting issue area. The ruling also approved the continuing efforts of the transition cost working group to work informally to develop a master data format for each utility to use in identifying costs for which they seek transition cost recovery, and asked that parties consider whether an audit to establish the starting point for transition cost recovery would be useful.

On August 1, 1996, Commissioner Duque, as co-assigned Commissioner in this issue area, issued a ruling endorsing an independent audit, with consultants to be hired by the Energy Division (formerly the Commission Advisory and Compliance Division), and establishing December 30, 1996 as the submission date for the final audit report.[2] A prehearing conference (PHC) was held on September 13 to identify Phase 1 issues and establish a schedule for evidentiary hearings. On September 23, Assembly Bill (AB) 1890 was signed into law by Governor Wilson. AB 1890, in many respects, built on our Preferred Policy Decision and confirmed that the transition period for electric restructuring would begin on January 1, 1998. In light on the anticipated legislation and at the direction of the assigned administrative law judge (ALJ), interested parties attended a meet-and-confer session on September 27. Three joint case management statements were filed by: 1) PG&E, Edison, SDG&E, and the Coalition of Utility Employees (CUE); 2) the Office of Ratepayer Advocates (ORA), The Utility Reform Network (TURN), the Utility Consumers' Action Network (UCAN), and the California Energy Commission (CEC); and 3) California Industrial Users (CIU), California Large Energy Consumers Association (CLECA), California Department of General Services (DGS), California Farm Bureau Federation (Farm Bureau), the Energy Producers and Users Coalition (EPUC), and Cogeneration Association of California (CAC).

These case management statements and the various procedural recommendations were addressed by ruling issued October 11, 1996. This ruling established a schedule for Phase 1 and Phase 2 and reorganized the importance of Phase 1A policy briefs. The purpose of Phase 1A was to delineate the major issues and policy determinations that must be resolved in these proceedings. On October 21, the utilities filed amended applications to reflect the impact of and revisions required by AB 1890, specifically the requirements of newly added PU Code §§ 367, 368, 369, 372, 373, 374, 375, and 376.[3] Because terms and conditions for exemptions were addressed in detail in §§ 372-374, the utilities were directed to provide proposed tariff language to comply with those provisions and to file tariff language for establishing the CTC

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[2] The date of the audit report has necessarily been extended to March 21, 1997, due to various procedural matters that delayed selection and contract execution with the selected consultants.

[3] All statutory references are to PU Code sections, unless otherwise noted.

balancing account. The Energy Division held workshops on the tariff language on January 13 and 14, 1997, and issued a workshop report on January 24. Comments on the workshop report were filed on February 5 by PG&E, Edison, SDG&E, and ORA.

Phase 1 testimony was served by ORA, jointly by TURN, DGS, and UCAN, (collectively, TURN *et al.*), jointly by CIU, CLECA, and CMA (collectively, CIU *et al.*), by the Federal Executive Agencies (FEA), by Sonoma County Water Agency (Sonoma County), and jointly by the EPUC and CAC (EPUC/CAC).[4] Evidentiary hearings were held from December 3 through December 10. Concurrent opening briefs were filed by PG&E, Edison, SDG&E, ORA, TURN *et al.* (together with the University of California/California State University, CIU *et al.*, FEA, Sonoma County, and EPUC/CAC. On January 28, a Joint Recommendation was submitted to the Commission by PG&E, Edison, SDG&E, CIU, CLECA, CMA, the Farm Bureau, EPUC, and CAC.[5] Reply briefs were timely filed by PG&E, Edison, SDG&E, ORA, TURN *et al.*, CIU *et al.*, Farm Bureau, Sonoma County, and FEA.[6] Oral argument was held on February 10, 1997. Supplementary briefs addressing the Joint Recommendation were filed on February 14 by ORA, TURN, DGS, PG&E, Edison, and SDG&E.

3. Assembly Bill 1890 and Transition Costs

AB 1890 adds several new sections to the PU Code, and endorses, for the most part, this Commission's approach to transition costs. With certain exceptions, the legislation provides for a nonbypassable CTC, to be levied on all customers, whether taking service as full service utility customers (or bundled customers), procuring their own energy as direct access customers, or departing the utilities' transmission and

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[4] We also address the points raised in Merced Irrigation District's (MID) Phase 1A brief, which PG&E rebutted in Exhibit 4.

[5] PG&E and SDG&E attached the Joint Recommendation to their reply briefs, filed on February 5, 1997.

[6] The Arvin-Edison Water Storage District also filed a reply brief. Arvin-Edison is not a party to this proceeding nor has it filed a petition to intervene. We will accept its reply brief as part of our correspondence file, but direct Arvin-Edison to take steps to become an Interested Party should it wish to attain party status.

distribution systems altogether (departing load customers). While the Preferred Policy Decision provided for a rate cap and recovery of transition costs through 2003, AB 1890 provides for a rate freeze at the June 10, 1996 rate levels and the recovery of the majority of transition costs by December 31, 2001. This rate freeze is linked to transition cost recovery; i.e., if generation-related uneconomic costs are recovered prior to December 31, 2001, the rate freeze will end.

In addition to the general categories of transition costs found eligible for recovery in the Preferred Policy Decision, § 367 provides for transition cost recovery of Biennial Resource Proceeding Update (BRPU) settlement costs, capital additions for units existing as of December 20, 1995 and which we find reasonable for maintaining facilities until 2002, Edison's fixed fuel contracts, and an expanded definition of employee-related transition costs. Section 367 also specifies the period during which particular transition costs may be recovered. Transition cost collection by means of the CTC begins January 1, 1998, simultaneously with the implementation of direct access, the ISO, and the Power Exchange. Costs of generation-related assets and obligations must be collected by December 31, 2001. Costs associated with power purchase contracts, including those QF contracts in place as of December 20, 1995, may be collected for the duration of the contract.

Employee-related transition costs are defined in § 375, which provides that these costs shall be added to the uneconomic generation-related costs and that recovery shall extend through December 31, 2006. In addition, the utilities are permitted to extend the collection period though March 31, 2002 to the extent collection of transition costs is impacted by CTC exemptions, the costs of renewable programs, or BRPU settlement costs, with certain additional provisions. Finally, § 376 provides that, to the extent that the costs of programs to accommodate implementation of direct access, the Power Exchange, and the ISO reduce the ability of the utilities to collect generation-related transition costs, those costs may be collected after December 31, 2001 in an amount equal to Commission-approved implementation costs. No time limit is specified.

Most importantly, in order to determine the transition costs for generation-related assets, we must net the negative (above-market) and positive (below-market) transition costs of all utility-owned generation-related assets. Valuation of these assets must occur by year-end 2001.[7] Significantly, the provision that the allocation of transition costs shall not result in rate increases beyond June 10, 1996 levels requires that the CTC portion of a given bill be computed on a residual basis; i.e., the difference between the total rate and all other charges, including the Power Exchange price.[8]

Section 368 delineates the criteria for plans for the recovery of transition costs identified in § 367. Among other criteria, this section requires that utilities amortize uneconomic costs such that their recorded rate of return does not exceed authorized rate of return on uneconomic assets and that utilities are at risk for transition costs not recovered during this period. We addressed the utilities' cost recovery plans in D.96-12-077.

In addition, § 381(d) states that the Commission shall extend the period for transition cost collection until March 31, 2002 to ensure that the aggregate portion of the research, environmental, and low-income funds allocated to renewable resources shall equal $540 million and that up to $50 million for resolving outstanding issues related to exemptions, and up to $90 million for resolving outstanding issues related to Edison's BRPU contracts, shall be collected during this extension.

4. Issues Addressed in Phase 1

This case has been bifurcated to capture the ratemaking issues in Phase 1 and the quantification issues in Phase 2. Phase 1 has been limited to deciding issues related to terms and conditions for those entities which are exempted from the CTC, determining the need for a market price proxy, and establishing the transition cost balancing accounts for each utility. Several parties have addressed the eligibility of

[7] For certain assets, market valuation is being addressed in PG&E's and Edison's divestiture applications (Application (A.) 96-11-020 and A.96-11-046, respectively).

certain costs for transition cost recovery in both Phase 1A policy briefs and Phase 1 testimony, apparently because of confusion as to where these matters were to be taken up. The ALJ issued a ruling on November 21 to clarify these matters.

In Phase 1, we address the ratemaking mechanisms proposed by PG&E, Edison, and SDG&E to track and recover transition costs, as well as the various proposed approaches to flexibility in applying revenues to costs and accelerating depreciation. In addition, we discuss the CTC responsibility for departing load and the establishment of the required fire wall in the accounting mechanisms for CTC exemptions to ensure that no cost-shifting occurs between the combined residential and small commercial class and remaining customer classes. The actual operation of the fire wall will be more fully considered in the unbundling and ratesetting proceeding (A.96-12-009 *et al.*). Finally, we must ensure that the balancing accounts are adequate to account for any proceeds from Rate Reduction Bonds, provided in AB 1890 as a means to finance the mandatory 10% rate reduction for residential and small commercial customers beginning January 1, 1998.

5. Balancing Account Issues

The most contentious issues in this phase involve determining the appropriate amount of utility discretion in applying transition cost revenues to incurred costs and deciding whether the utilities' requests for flexibility impacts the risk of transition cost recovery addressed in the statute and our Preferred Policy Decision. To the extent that utility proposals for ratemaking mechanisms to track transition cost recovery differ from current ratemaking approaches, we must determine whether this is acceptable.

The utilities assert that the proposed accelerated recovery of costs and deferral of certain current costs are required by AB 1890. Because AB 1890 provides for the recovery of employee transition costs and restructuring implementation costs after the end of the rate freeze (that is, after March 31, 2002), the utilities hold that such costs

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[8] It is very important to distinguish between transition costs and the competition transition charge or CTC. The CTC will be delineated on each applicable customer's bill as a separate nonbypassable charge, which will generate revenue to allow the utilities to recoup their uneconomic transition costs.

may be deferred in order to allow recovery of generation-related transition costs, which are at risk for recovery by December 31, 2001. In addition, because costs related to BRPU settlements, irrigation district exemptions, and the costs of providing renewable resource programs may be collected during the period after December 31, 2001 and before March 31, 2002, there have been proposals to defer these costs as well.

5.1. Joint Recommendation on Employee Transition Costs and Balancing Account Issues

This Joint Recommendation was crafted late in the schedule for Phase 1 and was brought to the ALJ's attention on January 29, after opening briefs were filed. The moving parties to this Joint Recommendation are CAC/EPUC, CIU *et al.*, Farm Bureau, CUE, PG&E, Edison, and SDG&E.

These parties ask the Commission to adopt the Joint Recommendation which would settle the most contentious issues in this case and provide certainty in the recovery of transition costs. In summary, the Joint Recommendation recommends the following:

1. The utilities should be given flexibility to accelerate depreciation and collection of those costs specified in § 367 that must be collected by December 31, 2001 (so-called "at-risk" costs) to minimize the potential for write-offs under Generally Accepted Accounting Principles (GAAP).
2. If necessary to allow for the recovery of those costs, the utilities may defer the recovery of employee-related transition costs and BRPU costs until after December 31, 2001, and may recover up to $50 million of at-risk costs attributable to irrigation district exemptions through March 31, 2002.
3. To the extent that the costs of renewable programs addressed in § 381(d) displace the recovery of these at risk transition costs, such at-risk costs may be recovered after December 31, 2001, but not later than March 31, 2002. Similarly, to the extent that the Commission-approved restructuring implementation costs addressed in § 376 displace the recovery of these at-risk costs, the § 367 costs may be recovered after December 31, 2001 until fully recovered.
4. The utilities agree to recover as much employee-related transition costs, BRPU-related transition costs, and irrigation district exemption-related transition costs as is feasible during the rate

freeze period, provided that such recovery does not inhibit the utilities' ability to recover the at-risk transition costs. Furthermore, the utilities will recover the current costs associated with employee-related transition costs, BRPU-related transition costs, and irrigation district exemption-related transition costs prior to recovering the costs of buy-downs and renegotiations of QF contracts and other power purchase agreements (on an aggregate basis) and prior to accelerating the recovery of nuclear decommissioning. Costs related to QF buy-outs, buy-downs, and restructurings should be addressed in the aggregate; therefore, in the short term, some contract modifications may increase costs, which will be offset by other modifications in the long term.

5. The issues related to the reasonableness and scope of employee transition costs should be deferred to future transition cost reasonableness reviews and would not be addressed in Phase 2.

6. CUE agrees to support implementation of the ISO, Power Exchange, and direct access by January 1, 1998, and CUE will continue to maintain that an environmental impact report is not necessary to evaluate major policy questions resolved by AB 1890. More specifically, CUE agrees not to contest the market structure issues at FERC, but may advocate before this Commission that divestiture is not the sole measure of horizontal market power and is not critical to achieve implementation of the competitive generation framework by January 1, 1998.

As we discuss below, we do not adopt this Joint Recommendation. Rather than giving this proposal "great weight," as urged by Edison, we consider this Joint Recommendation merely as one proposal among the various other proposals presented during Phase 1. Therefore, prior to discussing our findings in this regard, we summarize parties' positions and proposals regarding establishing the transition cost balancing accounts and the type of flexibility that should be provided to the utilities.

5.2. PG&E's Proposal

Absent the recommendations of the Joint Recommendation, the major dispute in this phase is whether certain costs which are incurred before 2001 must be recovered as current costs in the year incurred or whether their collection can be deferred until after 2001. PG&E contends that the employee-related transition costs, the renewable program costs, the irrigation district exemption costs, and the restructuring implementation costs related to direct access and establishing the Power Exchange and ISO are cost categories which are not included in current rates and thus would not have occurred but for industry restructuring. Moreover, because recovery of these costs as incurred will reduce PG&E's ability to collect what it characterizes as at-risk generation-related costs, PG&E believes that it is reasonable to apply revenues to these costs after December 31, 2001. PG&E recommends a limited after-the-fact reasonableness review of the utilities' exercise of flexibility in acceleration. PG&E therefore proposes an annual transition cost proceeding which would review the recovery of transition costs during the previous year to verify compliance with Commission-adopted guidelines and would also provide a forum for reasonableness review for those categories of costs that must be found reasonable in order to be recovered.

PG&E recommends that the following principles should be adhered to: 1) the utilities should have sufficient flexibility to avoid write-offs under GAAP; 2) the utilities should have sufficient flexibility to match CTC revenues with costs; 3) utilities should have flexibility to accelerate recovery of their generating assets to approximate market value; and 4) the utilities should attempt to minimize the ratepayers' costs and risks.

PG&E does not recommend an intensive review of its efforts to depreciate generation plants to market value because such a process would require litigation of market value of the plants on an annual basis. PG&E proposes to provide information reports to notify the Commission of its changes in depreciation schedules, which would not be subject to Commission review.

PG&E recommends establishing an overall transition cost balancing account mechanism, with three categories of cost accounts, all with several subaccounts, and one revenue account:

- The Current Costs Account includes the accelerated Diablo Canyon revenue requirement, current fossil assets revenue requirement, and current hydroelectric and geothermal revenue requirements.

- The Accelerated Costs Account includes the accelerated portion of the above costs, with the addition of accelerated fossil decommissioning expense and accelerated QF revenue requirements.

- The Post-2001 Costs Account includes those cost categories which may be recovered after 2001.

PG&E proposes to apply monthly revenues to current costs first, except that it would not apply these revenues to post-2001 employee transition costs incurred currently, and would either apply any remaining revenues to the accelerated costs subaccounts or carry over the remaining balance in the revenue account to the next month. To the extent that additional revenue remains, PG&E would then choose whether to apply these revenues to the post-2001 account. If PG&E chooses to allow the balance in the CTC revenue account to be carried over, a 90-day commercial paper interest rate would be applied to the balance; similarly, balances in the accelerated costs account or the post-2001 costs account would be carried over to the next month, using the same interest rate.

PG&E believes that it is not necessary for the Commission to prescribe rules for acceleration, because the utilities have a strong incentive to recover as much of the at-risk costs as possible by December 31, 2001. "Since ratepayer and shareholder interests are aligned in this regard, there is no reason for adopting strict rules which would mandate recovery of certain items over others." (PG&E's Reply Brief, pp. 5-6.)

PG&E wants to accelerate the recovery of these at-risk costs as quickly as possible, but states that it intends to do so consistent with both avoiding writeoffs of regulatory assets under GAAP and reducing its generation assets to their market value but not below; i.e., so that at the time of market valuation, book value approximates market value. According to PG&E, this means that acceleration priority might have to be given to generation plants that are due to be market valued, but possess book values in excess of market. But PG&E also states that the result will not be to increase ratepayer costs or to prolong the rate freeze.

PG&E asserts that adopting a strict requirement that puts recovery of regulatory assets last because they earn lower returns than generation-related assets could result in write-offs. PG&E would then be unable to conclude that it is probable that its regulatory assets will be fully recovered. PG&E asserts that such a requirement could deprive the utilities of fair opportunity to fully recover transition costs because its adoption could result in the write-off of regulatory assets at the outset, which would be in conflict with AB 1890. If these write-offs occurred for financial accounting purposes, they would not occur for ratemaking purposes. Therefore, PG&E would still collect these costs utilizing CTC revenues; however, PG&E states that financial write-offs would be significant and could negatively impact PG&E's bond ratings and access to capital markets. PG&E believes AB 1890, the Preferred Policy Decision, and the Rate Restructuring Settlement (authorized in AB 1890 as an example of a cost recovery plan) allow for this acceleration and flexibility. Because of the fixed recovery period, PG&E states that it is exposed to significant financial uncertainty in its ability to achieve full recovery.

The risk of write-off of plant costs is subject to different accounting standards and is less likely to occur, according to PG&E. Plant costs are subject to market valuation and must be divested, spun off, or appraised by 2001. At that time, if there are any unrecovered uneconomic costs, PG&E asserts that these uneconomic costs would become regulatory assets and therefore subject to the same risks as other regulatory assets.

In testimony and briefs, EPUC/CAC asserted that deferring recovery of certain current costs is inconsistent with AB 1890 and current ratemaking. According to PG&E, now that EPUC/CAC is a signatory to the Joint Recommendation, it now recognizes that atypical ratemaking (i.e., deferral of current costs in favor of acceleration of future at-risk costs) is appropriate in limited circumstances where specified in the legislation. Consistent with current ratemaking practices, PG&E intends to reduce ratebase by the amount of deferred taxes, thus reducing the return on ratebase and giving ratepayers the time value of money. However, PG&E asserts that such rate base reduction would not be appropriate for other regulatory assets, such as Post-retirement Benefits Other than Pensions (PBOPs), because these assets have already been net present valued in order to reflect the time value of money.

PG&E agrees that there is a general consensus that the Commission should adopt certain guidelines applicable to utility acceleration of transition costs that would serve as a framework for subsequent after-the-fact reasonableness reviews. PG&E suggests that the annual Revenue Adjustment Proceeding (RAP) proceeding may be appropriate.[9] PG&E recommends that the standard for review should be whether the utilities exercised reasonable judgment in balancing the conflicting guidelines for accelerated recovery, given the information available at the time. PG&E disputes TURN *et al.'s* contention that market value of all utility-owned generation-related assets should be determined administratively and that the utilities should be required to accelerate depreciation on these assets to a level determined annually by Commission. PG&E also disputes TURN *et al*.'s, ORA's, and FEA's contention that if utilities voluntarily defer costs, they should not earn interest on that deferral.

Finally, PG&E requests that the Commission should clarify that it is neither possible nor necessary to allocate transition cost responsibility to each rate schedule, tariff option and contract because the fire wall will adequately ensure that there is no cost shifting. This is a consensus recommendation by all parties, reached in the Energy Division workshops.

5.3. Edison's Proposal

Edison proposes that an overall transition cost balancing account be established with two categories of costs and separate subaccounts within each category. Category I costs include those current period costs that must be paid because of contractual obligations and costs which must be collected by December 31, 2001. For example, Edison proposes to establish Category I subaccounts which include QF transition costs and interutility contracts transition costs through 2001, as well as subaccounts for those costs which must be collected by year-end 2001, e.g., San Onofre Nuclear Generating Stations (SONGS) 2&3 sunk cost transition costs, Palo Verde Nuclear Generating Station sunk cost transition costs, fossil sunk costs transition costs,

[9] The RAP was discussed in D.96-12-077 and D.96-12-088.

and regulatory asset transition costs. Category II costs include those costs which may be collected after December 31, 2001, and Edison proposes to establish subaccounts for these cost such as, QF transition costs incurred post-2001, SONGS 2&3 Incremental Cost Incentive Pricing (ICIP) transition costs (for the period January 1, 2002 through December 31, 2003), regulatory asset transition costs (post-2001), employee transition costs, and restructuring implementation transition costs.

Under Edison's proposal, market revenues and other credits and costs would be recorded on a monthly basis in the appropriate subaccount of Category I or Category II. For costs, Edison proposes to accelerate the recovery of nuclear and fossil sunk costs over the four-year period 1997-2001. Therefore, Edison proposes that the monthly recorded sunk transition cost revenue requirement to be recorded in the Category I nuclear or fossil cost subaccount will equal the depreciation expense based on a straight-line 48-month amortization period, plus taxes and a 7.35% annual return.[10] All other transition costs would be recorded into the appropriate transition cost subaccount as incurred. Edison is not proposing to accelerate the recovery of these costs. Edison further states that these non-sunk transition costs will not earn a return.

For revenues, Edison proposes that CTC revenues would first be entered into the Category I revenue subaccount, through the end of the rate freeze period, and thereafter into the Category II revenue subaccount. Edison proposes that revenues not be allocated among the Category I cost subaccounts, but total revenues would be available to offset the overall balance of all Category I cost subaccounts summed together. This overall Category I balance would then accrue interest at the 90-day commercial paper rate, whether it is over- or under-collected.

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[10] In the Preferred Policy Decision, we determined that assets eligible for transition cost recovery would earn a reduced rate of return based on the embedded cost of debt for the debt component and 90% of the embedded cost of debt for return on equity. (Preferred Policy Decision, mimeo. at 123.) Section 367(d) affirmed this provision.

To the extent that the credit balance in the Category I revenue subaccount exceeds the overall net debit balance (i.e., Category I costs as incurred), Edison requests the flexibility to either leave any portion of that overcollection in the Category I account or transfer it to the Category II revenue subaccount, depending on the over- or under-collected status of the Category I and II accounts. Edison believes that this flexibility is necessary in order to apply GAAP principles for rate regulated companies to its financial statements for both Category I and Category II accounts. Edison therefore states that it cannot allow the Category I account to become too overcollected at the expense of Category II costs being too undercollected during the period.

In its opening brief, Edison explains that while Edison has proposed to amortize its generation sunk costs on a straight-line basis over a 48-month period, PG&E has proposed to recover its generation sunk costs in two components: a current cost component based on authorized revenue requirements (including associated taxes and full rate of return) and if additional revenues are available, an accelerated component at a reduced rate of return. Edison now states that in order to promote consistency among the three utilities, Edison would support PG&E's model. Therefore, Edison would create a new Category II subaccount to record accelerated costs, similar to PG&E's proposal, discussed above. All accelerated costs are subject to a reduced rate of return, as are nuclear sunk costs whether further acceleration is applied or not. Edison recommends that adjustments to sunk cost amortization be made annually and that these adjustments could be reviewed by the Commission in connection with the Revenue Adjustment Proceeding. Edison agrees with PG&E that the annual CTC reviews proposed by many parties do not provide an appropriate mechanism for consideration of appropriate adjustments to estimates of fair market value.

Like PG&E, Edison requests flexibility in managing the recovery of transition costs to mitigate the inherent risk due to the reduced time period for recovery. Edison urges the Commission to balance shareholder and ratepayer interests appropriately and contends that the proposals made by TURN *et al.* and ORA do not fairly balance the interests of shareholders, customers, employees, or potential new market entrants. Edison states that the proper interpretation of the statute based on the record is that employee-related transition costs were intended to be recovered post-2001, so as not to displace recovery of generation-related assets. Furthermore, Edison states that GAAP (specifically Financial Accounting Standards Board (FASB) Statement No. 71) precludes too large a disparity between costs incurred and those accruing in a balancing account; i.e., Edison must recover incurred costs at some point or write-offs will occur.

In its reply brief and supplemental brief regarding the Joint Recommendation, Edison states that the compromises achieved by the Joint Recommendation should be accorded great weight: the consumer representatives agreed to support the utilities' request for flexibility in the transition cost collection process; the consumer representatives received the utilities' commitment to recover transition costs as expeditiously as feasible, including those that may be deferred for post-2001 recovery. Employees have received the alleviation of risk that recovery of employee transition costs would displace recovery of other transition cost categories, which could result in the utilities' reluctance to offer a package of reasonable employee transition assistance.

Edison disputes TURN *et al.'s* recommendation that tax deductibility be considered when determining order of acceleration. Edison states that tax deductibility has no bearing on ratemaking recovery, but is a matter of federal and state tax laws; i.e., whether an asset is accelerated or amortized over a longer period for ratemaking purposes has no bearing on its tax deductibility. Edison also disputes FEA's allegation that lack of appropriate limits on the degree of discretionary flexibility on the utilities' balancing account treatment could create a competitive advantage for the utilities. Edison also recommends that issues regarding the 10% shareholder incentive for restructured QF contracts are not before the Commission in this phase of the proceeding.

Edison agrees with ORA that if regulatory assets are to be accelerated, their prepayment must be treated as a rate base offset in order to prevent a windfall to the utility, except that it must be the net amount (less any taxes due). In addition, Edison states that the rate base credit should also be adjusted regularly to reflect only the funds which have been received in advance of the time they would have been received absent the acceleration.

Edison disputes TURN / DGS, ORA's and FEA's contention that if utilities voluntarily defer costs, they should not earn interest. Edison states that if it has to pay the costs of employee transition programs, for example, shareholders would have to finance these outlays, thus incurring short-term interest costs; accruing interest on any unrecovered balances in transition cost balancing accounts is therefore a means to make shareholders whole for these short-term borrowing costs. In general, the matching principle requires that revenues within an accounting period be matched to the costs incurred to produce those revenues; however, Edison states that regulatory ratemaking and accounting can depart from a strict matching process and that establishing a balancing account mechanism recognizes that any mismatch between revenues and costs subject to balancing account treatment should not harm or benefit either ratepayers or utility shareholders.

5.4. SDG&E's Proposal

SDG&E proposes to divide its transition cost balancing account into six subaccounts to track the expenses and revenues for each component: fossil generation; nuclear; QF contracts; wholesale purchased power contracts; regulatory commitments; and rate reduction bonds. SDG&E agrees that flexibility is necessary to allow the utilities to manage their transition cost recovery and to minimize the risk of nonrecovery for those assets which must be fully amortized prior to the end of 2001. SDG&E recommends that if the utilities receive a return on their return-bearing assets for a shorter period of time than the Legislature intended, this would be inconsistent with AB 1890 and the Preferred Policy Decision, and we should therefore reject the ORA and TURN *et al.* proposal. SDG&E asserts that AB 1890 and Preferred Policy Decision grant utilities the discretion to defer recovery of employee-related transition costs incurred prior to January 1, 2002 until after December 31, 2001.

SDG&E believes that the Joint Recommendation is balanced in addressing the desire of customers to keep transition costs as low as possible, while providing utilities with a reasonable opportunity to recovery approved costs. SDG&E agrees with Edison that the standard for transition cost recovery is intended to be balanced between ratepayer and shareholder interests with a forward-looking view to a competitive future.

SDG&E agrees with PG&E and Edison that the Commission should reject the TURN *et al.* proposal that no interest be applied to current costs the utilities voluntarily choose to defer and agrees that the issue of tax deductibility is neither relevant nor material to the issue of asset acceleration.

5.5. TURN et al.

TURN *et al.* urge the Commission to regulate the recovery of transition costs such that the interests of ratepayers and shareholders are fairly balanced, in accordance with AB 1890, and that the utilities recover transition costs in a manner than minimizes total costs recovered from ratepayers. TURN *et al.* recommend that the CTC revenues should first be applied to current costs. Then, to the extent that any acceleration is allowed, TURN *et al.* recommend that, until such time as plants are depreciated to their anticipated market value, any accelerated CTC recovery should be applied first to those transition cost assets with a high rate of return and in a manner which provides the greatest tax benefits.[11] TURN *et al.* state that once plants have been depreciated to their fair market values, no further depreciation is appropriate and that this is an essential step in determining that the utilities recover as transition costs only the uneconomic portion of the net book value of the fossil capital investment, as required by § 367(c).

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[11] While the rate of return on assets eligible for transition costs is reduced, as provided for in the Preferred Policy Decision and § 367(d), this rate is still higher than the 90-day commercial paper rate that is generally applied to balances remaining in balancing accounts.

TURN *et al.* state that AB 1890 does not guarantee transition cost recovery, but affords the utilities an opportunity to recovery these costs. Moreover, TURN *et al.* assert that while GAAP rules for regulatory assets may be more stringent than for plants, this does not necessarily mean that these assets should be accelerated before plants earning a higher rate of return. TURN *et al.* recommend that we review the range of circumstances surrounding this recovery.

TURN *et al.* state that the utilities should be required to follow a consistent approach in establishing the transition cost balancing accounts. Annual proceedings are necessary to review each utility's adherence to the Commission-established guidelines for transition cost recovery. Finally, TURN *et al.* argue that utilities should not be allowed to assess interest on balances they voluntarily choose to carry in balancing accounts because they are deferring the application of revenues to those categories of costs which can be recovered post-2001.

In support of their proposal, TURN *et al.* stress that stranded costs and CTC are not interchangeable: while all transition costs may be recovered through CTC revenues, not all CTC revenues will be directly related to recovery of transition costs; rather, some of the CTC revenues will cover return and taxes associated with stranded costs. This distinction is important, TURN *et al.* allege, because utilities have been given a fair opportunity to fully recover stranded costs, but that recovery must be consistent with a strategy to keep total CTC paid by customers to a minimum.

TURN *et al.* recommend that their proposal should be implemented because it is straightforward, and relatively easy to implement, and will serve to minimize the total amount of CTC revenues that will need to be collected in order to provide an opportunity for full stranded asset recovery, which is consistent with § 330(t). Because TURN's *et al.* approach reduces the amount that pays for associated carrying costs, the CTC revenues that go to stranded asset recovery are maximized, allowing stranded asset recovery to be completed earlier. TURN *et al.* assert that the utilities' approach would lead to a higher total amount of CTC being collected in order to achieve full recovery and result in a longer period of CTC recovery. Furthermore, TURN *et al.* note that AB 1890 is silent on the issue of broad accounting flexibility, but specific regarding the expeditious completion of transition cost recovery.

TURN *et al.* state that avoiding writeoffs is a legitimate goal; however, the concept of risk is inherent in § 368(a), which states that "the electrical corporation shall be at risk for those uneconomic generation related costs not recovered during [the rate freeze] period." Furthermore, TURN *et al.* assert that there will be ample opportunities to consider whether preventive action is warranted and recommend that the utilities make annual filings that would provide a forum for raising concerns such as regulatory assets write-offs and acceleration to below-market values. TURN *et al.* agree that the RAP could serve to review, track, and compare costs and revenues and therefore can be the forum to identify and, where appropriate, address any threat of undue asset write-offs or below-market acceleration.

Given the degree of utility benefit from voluntary cost deferrals and control over whether such deferrals take place, TURN *et al.* recommend that their proposal to have such deferrals occur without interest is both reasonable and consistent with past Commission decisions. (D.93-12-044, mimeo. at pp. 21, 48; D.94-12-047, mimeo. at pp. 28, 31, 39-40.).

PG&E asserts that TURN *et al.*'s proposal to accelerate recovery of return-bearing assets first cannot decrease costs to ratepayers unless it is assumed that PG&E is able to recover CTC-eligible costs prior to year-end 2001. PG&E believes TURN *et al.*'s proposal would lead to write-offs of regulatory assets and that the potential dollar impact of TURN *et al.* 's proposal is relatively small; PG&E's witness calculates that it is $20 million over the 4-year period, but does not explain how this amount is derived.

Edison and SDG&E dispute TURN's *et al.* proposal that in addition to requiring costs with a high rate of return to be recovered before costs with a lower or no rate or return, the Commission should consider tax implications in establishing prioritization guidelines for accelerated recovery of various categories of costs. Edison states that the tax criterion is not valid for making acceleration decisions, because tax depreciation schedules would not be changed simply because amortization is accelerated for book or ratemaking purposes. TURN *et al*. concede that this is true for assets which are subject to tax depreciation schedules. For those assets not subject to tax depreciation, TURN *et al*. argue that the tax implications of accelerated recovery should be considered in establishing an order of priority. Furthermore, TURN *et al.* recommend that accelerated recovery of materials and supplies, inventories, and fossil decommissioning costs should be delayed because recovery of these costs may not provide tax benefits and because these assets may be sold along with the divested units during the transition period.[12]

TURN *et al*. emphasize that statutory interpretation by this Commission is essential, recommend that the views of single legislator or lobbyist are of little value in ascertaining legislative intent and remind us that the overriding principle for statutory interpretation is that first source for determining what a statute means is the statute itself. Finally, TURN *et al*. insist that nothing in the record supports PG&E's claim that "no party has opined or even suggested that sufficient headroom might exist that would allow PG&E to fully recover the $8 billion to $14 billion in CTCs during the four-year transition period" (PG&E's Brief, p. 16) and that the Commission should deem full recovery to be an improbable outcome. The majority of proposals in relation to balancing account issues presumed full stranded asset recovery prior to end of rate freeze period; in fact, if full recovery is not achieved by that time, concerns about the order of recovery and deferral of costs are less meaningful. TURN *et al.* recommend that the common presumption should be that full recovery is feasible.

5.6. ORA

ORA recommends that the utilities should sequence costs to be recovered on an accelerated basis so as to minimize ratepayer costs and agrees with the TURN *et al.* proposal. Specifically, ORA recommends that the utilities should pay current costs first, including employee transition costs and the costs related to

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[12] The eligibility of these costs for transition cost recovery will be addressed in Phase 2.

renewable programs, prior to accelerating the recovery of future costs. ORA states that it is important to adhere to the matching principle of paying current costs out of current revenues. ORA agrees that the utilities should accelerate cost recovery of categories with high carrying costs first, which will reduce ratepayer interest payments to shareholders and create more headroom for the recovery of transition costs, and agrees with TURN *et al.* that this is similar to paying off credit cards with high interest rates first, then paying off lower cost loans.

ORA recommends that utilities accelerate the transition costs associated with fossil plants to but not below estimated market value. However, ORA states that hydroelectric, geothermal and other renewable assets should be retained by the utilities and should not be accelerated, but should be subject to generation PBR recovery, as provided for in the Preferred Policy Decision.

ORA further recommends that the utilities treat regulatory assets such as prepaid taxes as offsets to ratebase, which allows the utilities flexibility, but leaves ratepayers neutral regarding the management of transition costs. ORA also states that utilities should defer acceleration of non-plant assets, including fuel inventories, materials and supplies, and decommissioning costs, until after divestiture, because of a high likelihood that the associated assets might be sold during the transition period. ORA recommends that the utilities' acceleration of costs should be consistent with GAAP and that the pre-payment of certain post-2001 expenses should not be permitted. ORA asserts that costs from QF contracts or Power Purchase Agreements should not be accelerated. ORA recommends that the utilities should pay employee-related transition costs as incurred and collect after 2001 only those costs incurred after 2001. ORA agrees with EPUC that the utilities are not allowed to defer until after 2001 recovery of all costs associated with irrigation district exemptions under § 374. ORA urges that AB 1890 be narrowly construed to prevent CTC extending indefinitely into the post-2001 time period to the detriment of ratepayers and customers, but agrees that the effect of § 376 is to defer the recovery of certain current restructuring implementation costs until after 2001.

ORA points out that the TURN *et al.* approach does not restrict utilities' flexibility in terms of which plants to accelerate; rather, the aim is to dictate the sequence of accelerated recovery among categories of costs. ORA does not dispute that recovery of regulatory assets may be accelerated in accordance with GAAP but points out that write-offs would not occur unless there was a danger of transition costs not being collected within the headroom, which would result in write-offs anyway. Therefore, ORA agrees with TURN *et al.*: If all eligible transition costs are not collected at the end of the statutory periods, then a sequencing proposal does not matter; however, if the utilities can collect their transition costs during this period, then paying off the high carrying cost balances first benefits both ratepayers and shareholders.

Because there is no record to support the assertion that PG&E is unlikely to recover all sunk costs during the transition period, as PG&E claims in its opening brief, ORA recommends that the Commission should craft regulatory policies and mechanisms responsive to possibilities of both sufficient and insufficient headroom. ORA agrees with TURN *et al.* that the statutory interpretation must be based on the plain language of the statute.

ORA contends that costs which are voluntarily deferred should not earn interest; however, ORA agrees that costs which are deferred only because of inadequate current revenues to cover all current costs would be eligible for interest at the commercial paper rate only until such time that current revenues would allow payment of costs. ORA clarifies that it does not endorse the pro-rata approach, but instead recommends that earning no interest on voluntarily deferred costs would achieve the same result as matching current revenues with expenses and is a compromise between the more restrictive pro-rata approach and the flexibility sought by the utilities with regard to deferrals.

Finally, ORA believes that consistency among utilities in the balancing account structure will facilitate Commission oversight, but states that the accounts or tariffs do not need to be standardized.

5.7. FEA's Recommendations

FEA recommends that transition costs should be recorded in sufficient detail to enable the utilities, the Commission, and other parties to track and review each category of cost, that the cost categories and subaccounts should relate directly to AB 1890 and the Preferred Policy Decision, and that balancing account mechanisms and the accounting for CTC revenue should be as uniform as possible to facilitate comparative analysis and achieve consistency in the applicability of nonbypassable CTC.   FEA also states that the accounting must include sufficient detail to fulfill the fire wall provisions of AB 1890 and therefore recommends that balancing accounts be established, rather than memorandum accounts.

FEA advocates establishing the following guidelines:

1. The recovery of accelerated transition costs should be guided by the principle of cost minimization. Therefore, FEA agrees with TURN and ORA that utilities should be required to accelerate collection of costs first which earn full rate of return and which are tax deductible. FEA also recommends a rate base offset.
2. The overall objective of creating a fair and competitive market should be considered in conjunction with the objective of balancing the interests of shareholders and ratepayers. Therefore, appropriate limits should be set on the degree of flexibility granted to the utilities.
3. To the extent such recovery is permitted, recovery of materials and supplies, fuel inventory, and fossil decommissioning costs should be deferred (i.e., not accelerated) until market valuation occurs, because the utilities' recovery of such items is likely to be resolved when market valuation occurs.
4. Assets should be written down to estimated market value, but not to zero or below market value.
5. Employee transition costs incurred prior to 2001 should be recovered as much as possible before 2001, rather than deferring such collection. Deferrals of uncollected employee transition costs beyond 2001 should not earn interest after 2001.
6. Because recovery of QF and purchased power costs is permitted over the life of the contract, such costs should not be accelerated.
7. Costs should be recognized in the period benefitted. Because shareholders can retain 10% of net ratepayer benefits associated with restructured QF contracts, it would be appropriate to

coordinate the timing of this cost recognition with the period during which ratepayers benefit.

8. Utilities should manage the 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 over-collections of CTC.
9. Utilities should attempt to minimize ratepayers' costs and risks.
10. Conformance with GAAP is important in determining which CTC-eligible costs to accelerate. However, the previous guidelines may make write-offs under GAAP inevitable; therefore, adherence to GAAP should be one consideration, but not an overriding consideration.

FEA recommends an annual CTC proceeding, with annual and monthly reports by the utilities. The annual CTC proceeding should consider the reasonableness of previous CTC-eligible costs during the prior year and to provide a review of utilities' acceleration of CTC-eligible costs during previous year.

FEA is concerned about how the utilities propose to apply interest to the various components of the transition cost balancing accounts. For example, PG&E proposes to credit the CTC Revenue account at the commercial paper rate of interest for balances it decides to leave in this account. Simultaneously, PG&E would accrue an interest expense, computed at a significantly higher rate of interest, on its generation assets; therefore, PG&E would by choice leave a balance in the CTC revenue account rather than applying that balance to reducing higher interest-bearing transition cost balances, which at the same time, it chooses not to accelerate. FEA recommends that this should not be allowed or that revenue balances accrue interest at the rate of return applied to nuclear and fossil assets.

FEA asserts that the amounts of transition cost associated with regulatory assets are speculative; the amounts of regulatory assets eligible for CTC are a quantification issue which will be addressed in Phase 2 and may be a disputed factual issue. FEA states that the proposed accounting for accelerated recovery of Diablo Canyon sunk costs is inconsistent with PG&E's accounting of other accelerated transition costs and should be modified. PG&E proposes to record these costs in the current costs CTC account. FEA recommends that the restructuring implementation costs addressed in § 376 should be recorded on the utilities' books rather than using memorandum accounts. Because these are incurred costs, this separation should be formalized by using separate balancing accounts and/or subaccounts for costs and CTC revenues associated with each side of the fire wall.

FEA does not support major elements of the Joint Recommendation, although it generally agrees with certain statements. FEA disagrees with the recommendation that the utilities may select the order and degree of recovery of individual transition cost accounts and subaccounts as necessary to minimize the potential for write-offs which may occur under GAAP. FEA disputes the idea that litigation of reasonableness and legitimacy of employee-related transition costs should not take place in Phase 2 of these proceedings; rather, Phase 2 should be used to establish guidelines for reviewing and assessing the reasonableness of these costs and whether these costs should be offset by savings of employee-related costs reflected in existing rates.

5.8. CIU et al.

In testimony and in opening briefs, CIU *et al.* recommend that no placeholder be held open for "other" transition cost subaccounts and that future annual proceedings with time for presentation of evidence are necessary to consider reasonableness of costs, amount, and eligibility of costs. CIU *et al.* suggest workshops to design a streamlined CTC procedure that will allow for full evidentiary hearings. CIU *et al.* recommend that the utilities should not be granted complete flexibility in recovery of CTC, particularly in terms of deferring recovery of costs eligible for post-2001 recovery. Other than § 376, there is no legal requirement for such deferral. In reply briefs, CIU *et al.* urge approval of the Joint Recommendation.

5.9. EPUC/CAC

In testimony and opening briefs, EPUC/CAC recommend that flexibility be permitted for recovery of restructuring implementation costs (because § 376 specifically grants deferred recovery) and for employee-related transition costs (because AB 1890 is generally concerned with protecting utility employees and so states in its intentions). However, for all other categories of post-2001 costs, EPUC/CAC recommend that costs and revenues be matched. EPUC/CAC contend that the Legislature intended to expose the utilities to some risk and that the Commission should therefore require the utilities to recover transition costs and renewable program costs on an ongoing basis throughout the rate freeze period. EPUC/CAC state that unlimited flexibility alters the balance of benefits to ratepayers and shareholders intended by providing a rate freeze and the requirement that most transition cost recovery end December 31, 2001. EPUC/CAC propose that the utilities be required to recover the annual amortization of all eligible transition costs on a pro rata basis, including those costs which extend beyond the year 2001; that is, the monthly CTC revenues booked to the Transition Cost Balancing Account should be assigned to subaccounts based upon the relationship of the particular subaccount to the total transition cost balance.

5.10. CUE

CUE states unequivocally that reasonable employee transition costs are an obligation of ratepayers and any ratemaking mechanism that is adopted must not put the collection of generation-related transition costs at risk. According to CUE, legislative history demands this interpretation. CUE believes that if employee transition costs must compete for recovery with the recovery of generation-related transition costs, shareholders could ultimately be responsible for these costs. CUE asserts that this risk could impact the utilities' willingness to offer reasonable transition benefits to their employees, as intended by the Legislature and the Commission. Therefore, CUE recommends that the Joint Recommendation be adopted.

5.11. Farm Bureau

The Farm Bureau agrees that an equitable balance must be maintained between ratepayer and shareholder interests and recommends that well-constructed annual transition cost proceedings will be necessary to ensure that balance is struck. The Farm Bureau also recommends that no additional exemptions to the CTC be granted, as discussed more fully below, and has expressed concerns regarding departing load lump-sum payments, which are addressed in the terms and conditions discussion.

6. Discussion

6.1. The Joint Recommendation Is Not a Settlement and Is Accorded Appropriate Weight

As a threshold matter, we reject the proposed Joint Recommendation on both substantive and procedural grounds. We discuss the procedural concerns first.

We are very concerned regarding the allegations of TURN *et al.* and ORA that they were systematically excluded from negotiations and discussions. Although this proposal is not presented as a settlement and is not being reviewed as a settlement, excluding active parties from discussions about proposal which are eventually brought before this Commission only weakens the recommendation, particularly when such proposals are submitted only days before reply briefs are due. Not only does this exclusion impact the ability of objecting parties to respond appropriately in briefs, it has the potential effect of impacting the entire time line of this proceeding. Certainly, the moving parties' recommendation would have carried more weight had the representatives of small consumers been included in these discussions.

Rule 51(d) states that "'stipulation' means an agreement between some or all of the parties to a Commission proceeding on the resolution of any issue of law or fact material to the proceeding." Edison states specifically that the Joint Recommendation does not fit this definition, but instead "represents the consensus of its signatories to modify their positions in this proceeding and jointly recommend that consensus to the Commission. Because the issue arose from differing interpretations of the complex interplay of statutory provisions in AB 1890, it took approximately six weeks of discussions to arrive at this consensus." (Edison's Supplemental Brief, p. 9.) We agree that the parties to the Joint Recommendation appear to have reversed their positions on several issues. Such agreements coming in so late in this phase are problematic for two reasons. While the Commission wishes to encourage informal negotiations and consensus among the parties, it is difficult to evaluate why such a change in position has ensued. If such agreements were submitted well before opening briefs, those briefs could have provided more explanation and rationale. Secondly, as we move forward in implementing electric restructuring, the schedules for hearings in many issue areas will necessarily be compressed. We reject this fact as a reason to exclude active parties from discussions intended to arrive at consensus agreements. Certainly, if this joint recommendation had been presented as a settlement (and not necessarily an all-party settlement), it would have carried more weight. [13] We therefore accord the Joint Recommendation appropriate weight, as it is not a settlement, and appears to be merely a consolidation of certain interpretations of AB 1890. As we move forward to implement AB 1890, statutory interpretation is not a duty that we can relinquish to the parties, as we discuss below.

6.2. The Joint Recommendation Addresses Issues Beyond The Scope of This Proceeding

Furthermore, the Joint Recommendation proposes consensus treatment of issues that are beyond the scope of this proceeding. This document was filed in the above-captioned transition cost proceedings, not in the electric restructuring rulemaking. Therefore, even assuming for argument's sake that we were persuaded by the Joint Recommendation, we would be unable without further process to address elements of the Joint Recommendation that are outside the scope of the transition cost proceeding. For example, parties in R.94-04-031/I.94-04-032 have not had the opportunity to respond to or assess the reasonableness of CUE's position at FERC or its position regarding the divestiture applications.

In addition, as ORA discusses in its supplemental brief, the acceleration of QF renegotiations is being addressed in R.94-04-031/ I.94-04-032, in which we are reviewing various proposals for streamlining the restructuring and approval process

[13] As we found in D.96-01-011, if settling parties choose not to accommodate all affected interest groups, an all-party settlement cannot be achieved and our standard of review is heightened. (D.96-01-011, mimeo. at pp. 24, 266.)

for QF contracts. We decline to review portions of the Joint Recommendation that address these issues on a piecemeal basis.

6.3. Statutory Interpretation

While we are interested in the proponents' interpretation of the statutory language, it is this Commission's duty to implement the statute according to the plain meaning of the statute and to look to the legislative history where there is ambiguity, according to established rules of statutory construction. These rules do not include necessarily accepting the interpretations of the parties, despite the fact that certain parties were active in the AB 1890 discussions. As we recently stated in D.97-02-014:

> "When construing the purpose and intent of a statute, the California Supreme Court has clearly stated that it is of little assistance to consider the motives or understandings of single individuals, because such views may not reflect the views of other Legislators who voted for the bill. (Freedom Newspapers, Inc. v. Orange County Employees Retirement System Board (1993) 6 Cal. 4th 821, 831.) This admonition is particularly apt in this instance, where lobbyists and private proponents of legislation are relying upon their own views and intentions in arguing for a particular interpretation of AB 1890." (D.97-02-014, mimeo. at 49.)

The only way in which we could find the Joint Recommendation persuasive is if the Commission's own independent review of the statute leads to the same conclusion as to what the Legislature intended, as TURN *et al.* point out. (Supplementary Brief of TURN *et al.*, p. 3.) Again, we turn to our previous findings in D.97-02-014:

> "To determine that intent, we first turn to the language of the statute. (Delaney v. Superior Court (1990) 50 Cal. 3d 785, 798.) The United States Supreme Court stated this principle as follows:
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> "'[I]n interpreting a statute, [one] should always turn to one cardinal rule before all others. We have stated time and again that [one] must presume that the legislation says in statute what it means and means in statute what it says there.' (Connecticut National Bank v. German (1992) 503 U.S. 249, 253-254; 112A S.Ct. 1146, 1149.)
>
> "The California Supreme Court explains this fundamental principle more expansively:

> "'Pursuant to established principles, our first task in construing a statute is to ascertain the intent of the Legislature so as to effectuate the purposes of the law. In determining such intent, a court must look first to the words of the statute themselves, giving to the language its usual, ordinary import and according significance, if possible, to every word, phrase and sentence in pursuance of the legislative purpose. A construction making some words surplusage is to be avoided.' (Dyna-med, Inc. v. Fair Employment and Housing Commission (1987) 43 Cal. 3d 1379, 1386-1387, 241 Cal. Rptr. 67, 70.)" (D.97-02-014, mimeo. at 41.)

We must use these clearly-stated guidelines to implement the newly-added Public Utilities Code sections relating to transition cost recovery. Because there is no specific reference to accounting methodology in the statute, we must apply our knowledge of current ratemaking practices, common sense and our duty in carrying out the public interest in looking to the words of the statute, giving each word its usual, ordinary import.

First, while AB 1890 provides the utilities with a fair opportunity to fully recover transition costs, we do not find that AB 1890 ensures that transition cost recovery is without risk. Therefore, we reject the proposition that write-offs must be avoided at all costs. Again, we look to the unambiguous wording of the statute.

Section 1(b) of AB 1890 reads as follows:

> "(b)… It is the…intent of the Legislature that during a limited transition period ending March 31, 2002, to provide for all of the following:
>
> "(1) Accelerated, equitable, nonbypassable recovery of transition costs associated with uneconomic utility investments and contractual obligations.
>
> "(5) a fire wall that protects residential and small business consumers from paying for statewide transition cost policy exemptions required for reasons of equity or business development and retention.
>
> "(6) Protection of the interests of utility employees who might otherwise be economically displaced in a restructured industry."

Section 330 states, in relevant part:

"(s) It is proper to allow electrical corporations an opportunity to continue to recover, over a reasonable transition period, those costs and categories of costs for generation-related assets and obligations, including costs associated with any subsequent renegotiation or buyout of existing generation-related contracts, that the commission, prior to December 20, 1995, had authorized for collection in rates and that may not be recoverable in market prices in a competitive generation market, and appropriate additions incurred after December 20, 1995 for capital additions to generating facilities existing as of December 20, 1995 that the commission determines are reasonable and should be recovered, provided that the costs are necessary to maintain those facilities through December 31, 2001. In determining the costs to be recovered, it is appropriate to net the negative value of above market assets against the positive value of below market assets.

"(t) The transition to a competitive generation market should be orderly, protect electric system reliability, provide the investors in these electrical corporations with a fair opportunity to fully recover the costs associated with commission approved generation-related assets and obligations and be completed as expeditiously as possible.

"(u) The transition to expanded customer choice, competitive markets, and performance based ratemaking …can produce hardships for employees who have dedicated their working lives to utility employment. It is preferable that any necessary reductions in the utility work force directly caused by electrical restructuring, be accomplished through offers of voluntary severance, retraining, early retirement, outplacement, and related benefits. Whether work force reductions are voluntary or involuntary, reasonable costs associated with these sorts of benefits should be included in the competition transition charge."

Finally, Section 368(a) provides, as follows:

"The cost recovery plan shall set rates for each customer class, rate schedule, contract, or tariff option, at levels equal to the level as shown on electric rate schedules as of June 10, 1996, provided that rates for residential and small commercial customers shall be reduced so that these customers shall receive rate reductions of no less than 10 percent for 1998 continuing through 2002. These rate levels for each customer class, rate schedule, contract, or tariff option <u>shall remain in effect until the earlier of March 31, 2002, or the date on which the commission-authorized costs for utility generation-related assets and obligations have been fully recovered. The electrical corporation shall be at risk for those costs not recovered during that time period. Each utility shall amortize</u>

> its total uneconomic costs, to the extent possible, such that each year during the transition period its recorded rate of return on the remaining uneconomic assets does not exceed its authorized rate of return for those assets. For purposes of determining the extent to which the costs have been recovered, any over-collections recorded in the Energy Costs Adjustment Clause and Electric Revenue Adjustment Mechanism balancing accounts, as of December 31, 1996, shall be credited to the recovery of the costs." (Emphasis added.)

The only language in AB 1890 that speaks to possible deferral of current costs is addressed in Section 376, which states:

> "To the extent that the costs of programs to accommodate the implementation of direct access, the Power Exchange, and the Independent System Operator, that have been funded by an electrical corporation and have been found by the commission or the Federal Energy Regulatory Commission to be recoverable from the utility's customers, reduce an electrical corporation's opportunity to recover its utility generation-related plant and regulatory assets by the end of the year 2001, the electrical corporation may recover unrecovered utility generation-related plant and regulatory assets after December 31, 2001, in an amount equal to the utility's cost of commission-approved or Federal Energy Regulatory Commission approved restructuring-related implementation programs…." (Emphasis added.)

No other clause in any other sections relating to transition costs specify this sort of recovery. Therefore, it is clear that these § 376 costs can be deferred.

It is particularly important to read § 381(d) in the context of both § 381 and the entire statute as a whole. PG&E, Edison, and SDG&E assert that to the extent that generation-related transition cost recovery is impacted by the recovery of renewable program costs, this "displaced" transition cost recovery may be deferred and recovered in the three-month period which extends the rate freeze, beginning on January 1, 2002.

Section 381 addresses both the funding of various public purpose programs and the collection and recovery of those funds. One purpose of § 381(d) is to allow no more than $75 million to be collected through the CTC so as to allow the funding level for renewable programs to equal $540 million, as we have stated in D.97-02-014, Ordering Paragraph 2(d):

> ". . . Pursuant to PU Code § 381(d), an additional $75 million shall be collected by a three-month extension of the competition transition charge beyond its otherwise applicable termination of December 31, 2001. These funds shall be transferred to the CEC pursuant to § 383(a)."
> (D.92-02-014, mimeo. at p. 92.)

We agree with the utilities that, other than this additional $75 million which is to be collected through the CTC during the extended 3-month period of the rate freeze for purposes of funding the renewables programs, other costs of funding these programs and other public purpose programs as addressed in § 381 and D.97-02-014 are collected through a separate nonbypassable charge. We also agree that the costs of funding the renewable programs cannot be deferred. While the issue of deferral of generation-related transition costs and "displaced" recovery is not addressed in either §§ 381(d), 367, or 368, we must consider the interrelationship of the rate freeze, the collection of funding for the renewable program costs, and headroom.

As previously discussed, rates are frozen at the June 10, 1996 levels. Funding for the renewable program costs addressed in § 381(b)(3) is not provided for within these rate levels. Because the statute allows the utilities a fair opportunity to fully recover transition costs, as discussed above, it is reasonable that to the extent the funding of these programs jeopardizes the recovery of generation-related transition costs by December 31, 2001, (i.e., reduces headroom), those displaced costs may be recovered during the three-month extended period for CTC collection. However, this deferral should only occur to the extent necessary; i.e., the utilities should make every effort to recover all generation-related transition costs before December 31, 2001. In addition, any carrying costs associated with funding the renewable program costs must be borne by the shareholders and will not be collected as transition costs.

In addition to authorizing the $75 million to be allocated to funding renewables programs, § 381 allows the 3-month extension of the rate freeze to continue to collect certain other costs. These funds are then to be reallocated for purposes of funding renewable programs, to the extent additional moneys remain after funding costs associated with § 374 (outstanding issues related to implementation of irrigation district exemptions) and issues related to Edison's contract arrangements in the BRPU settlements, as described in § 381(c) (4) and § 381(c)(5), as follows:

> "(4) Up to fifty million dollars ($50,000,000) of the amount collected pursuant to subdivision (d) may be used to resolve outstanding issues related to implementation of subdivision (a) of Section 374. Moneys remaining after fully funding the provisions of this paragraph shall be reallocated for purposes of paragraph (3).
>
> "(5) Up to ninety million ($90,000,000) of the amount collected pursuant to subdivision (d) may be used to resolve outstanding issues related to contractual arrangements in the Southern California Edison service territory stemming from the Biennial Resource Planning Update auction. Moneys remaining after fully funding the provisions of this paragraph shall be reallocated for purposes of paragraph (3)."

Therefore, we find that deferral of recovery of generation-related transition costs to the three-month period, beginning January 1, 2002 and ending March 31, 2002, is permitted by § 381(d). The CTC is extended for three months beyond its otherwise applicable termination date to accomplish the following collection purposes: 1) $75 million is to be collected in the CTC in the three-month period beginning January 1, 2002 and allocated to the funding of renewable programs; 2) up to $50 million may be collected in the CTC in this three-month period for purposes of funding outstanding issues related to implementation of § 374; any remaining funds of this amount are allocated to renewables; 3) up to $90 million may be collected in the CTC in this three-month period for purposes of funding outstanding issues related to Edison's BRPU settlements; any remaining funds of this amount are allocated to renewables. Any other funds collected during the three-month period shall be applied to the deferred generation-related transition costs. This approach both ensures that the aggregate portion of the funds allocated to renewable resources equals $540 million and ensures that the costs of these programs are collected, as is required by the statute.

6.4. Shareholder and Ratepayer Interests Should Be Aligned

It is in the interests of both ratepayers and shareholders that the greatest amount of revenues be available to collect transition costs. Ratepayers benefit because if transition costs are collected as expeditiously as possible, the rate freeze may end before the end of the mandated transition period. Shareholders benefit because if the utilities maximize the amount of available dollars to recover actual transition costs, rather than interest and carrying costs, there is a greater chance of full recovery of those costs. Even PG&E agrees that "because it is uncertain how much headroom will be available and whether utilities would be able to recover all of their at risk transition costs during the rate freeze, the utilities will of necessity accelerate costs in a manner that maximizes recovery and minimizes the risk of write-offs." (PG&E's Reply Brief, p. 5). PG&E also agrees with TURN *et al.* 's conclusion that the accelerated recovery of transition costs of assets bearing higher rates of return "would benefit shareholders as well [as ratepayers], because if more of the CTC revenue is applied against stranded costs themselves rather than towards interest there is less of an opportunity that utilities will forgo recovery of some stranded costs and hence less likelihood of an adverse reaction by financial markets." (PG&E's Reply Brief, p. 7, quoting TURN *et al.'s* Opening Brief.) PG&E has stated that "TURN correctly recognizes that IOU and ratepayer interests are aligned; ratepayers want the freeze to end as soon as possible and IOUs want to recover all of their at risk costs as soon as possible." (PG&E's Reply Brief, p. 5.) In its original proposal in this proceeding, Edison recommends accelerated recovery of transition costs for only those assets earning a rate of return.

Accelerating cost recovery for the assets earning a rate of return will allow ratepayers to benefit in another way. As FEA points out, the utilities are proposing to apply a relatively low interest rate (the 90-day commercial paper rate) to the revenue account, to the extent that the utilities choose to leave a balance remaining in these accounts. At the same time, the utilities would be earning a somewhat higher rate of return on generation assets on which they similarly chose not to accelerate depreciation. Therefore, if utilities are allowed to accelerate recovery of costs of assets that do not bear a rate of return before those that do, the utilities will earn the higher rate of return, while the ratepayers earn only the commercial paper interest rate on the revenue account. This is an inequity that is counter to the intent of the statute and must be avoided.

6.5. It is Premature to Assume that Regulatory Assets Are At Risk

Generally, parties have agreed that, except for employee-related transition costs and restructuring implementation costs, current costs should be recovered first. PG&E defines current costs as those costs which are being recovered in today's rates, including depreciation on a regular schedule. (TR: 208-209.) In its original proposal, Edison defines current costs to include accelerated depreciation on a 48-month amortization schedule, including associated taxes and a reduced rate of return. PG&E argues that it needs flexibility to determine which assets should be depreciated more quickly, and that this acceleration cannot be done on a predetermined basis. PG&E asserts that assets should be depreciated to market value, but not below. PG&E recommends that recovery of regulatory assets should be accelerated first (that is, the difference between what is scheduled to be included in current rates and the total amount of regulatory assets at risk). Therefore, PG&E would not accelerate cost recovery of any of the depreciable assets so long as it believed that the regulatory assets were at risk. Edison does not take a position on regulatory assets, other than stating that there should not be too great a disparity between Category I cost recovery and Category II cost recovery, which might otherwise trigger write-offs under FASB Statement No. 71.

In the Preferred Policy Decision, we defined regulatory obligations as:

> "the transition costs that . . . are related to various deferred costs and outstanding balancing accounts balances that the utility has accrued under cost of service regulation. In most cases, we have already approved recovery of these costs, and they are reflected in outstanding balances of balancing accounts. Examples of these types of costs include deferred operating expenses, deferred taxes, unamortized loss from sale of assets, unamortized debt expense, costs associated with issuing or reacquiring debt, and nuclear decommissioning expenses.
>
> "We plan to evaluate specific account balances and determine the amounts that will be included as part of transition costs during the implementation phase of this rulemaking, but these amounts should

> relate only to generation assets affected by this restructuring." (Preferred Policy Decision, mimeo. at pp. 133-134.)

It is premature to conclude that write-offs of regulatory assets will be required for financial accounting purposes. Various definitions of regulatory obligations have been presented by the utilities and parties in Phase 1A of this proceeding. We have not yet adopted a definition of regulatory assets for purposes of transition cost recovery, but will determine the applicable definition to be used in defining regulatory assets in Phase 2 of this proceeding. We note that at least two decisions have been issued after the Preferred Policy Decision and shortly before AB 1890 was signed into law that create additional "regulatory assets."[14] It is not clear at this point whether regulatory assets are properly categorized. In fact, in D.88-12-094, we found that we were not prepared to adopt FASB Statement No. 71 for ratemaking purposes. (30 CPUC 2d 506, 520.).[15]

We note that in D.92-12-015, we accepted the following definition in terms of PBOP and the applicability of FASB Statement No. 106:

> "A regulatory asset is the recording of the utilities' costs not currently recoverable for ratemaking purpose[s]. To qualify as a regulatory asset, it must be probable that future revenue in the amount at least equal to the asset will result from inclusion of that cost in allowable costs for ratemaking purposes and must be based on available evidence that future revenue will be provided to permit recovery of the previously

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[14] D.96-09-037 was issued on September 4, 1996, shortly before AB 1890 was signed into law. In that decision, we adopted a settlement which provided, among other things, that the weighted-average rate base of prior years' revenue requirement to be placed in PG&E's rate base as a regulatory asset will be for $14.40 million for 1995. D.96-06-061 was issued on June 19, 1996. Again, this decision created a regulatory asset. "The loss on depreciable property will be recovered from ratepayers, although not through rate base, but rather through creation of a 'regulatory asset.' . . . This credit will be offset by the new $1,577,000 'regulatory asset' which will be amortized over a 5-year period (1996 through 2000). (fn: Base revenues in the period from 1977 through 2000 will include an annual $376,000 allotted to assure that the regulatory asset set up can be fully amortized." (D.96-06-061, mimeo. at 10.)

[15] We do not necessarily require that the utilities we regulate adhere to particular FASB statements for ratemaking purposes. In D.88-03-072, the Commission declined to endorse FASB Statement No. 87, finding that considerations other than consistency with GAAP should be considered and that GAAP should not be determinative for ratemaking purposes. (27 CPUC 2d 550, 552.)

> incurred cost rather than to provide for expected levels of similar future costs." (46 CPUC 2d 499, 536.)

Pursuant to § 367, the Commission must make final determinations of the uneconomic costs associated with generation-related regulatory assets and obligations.

The FASB is an authoritative body which establishes a common set of accounting concepts, standards, procedures, and conventions, which are widely known as "Generally Accepted Accounting Principles" or "GAAP" and are used by most enterprises to prepare external financial statements. We note that FASB Statement No. 71 has been modified by FASB Statement No. 90, FASB Statement No. 92, and most recently by FASB Statement No. 121, which amends FASB Statement No. 71, paragraphs 9 and 10, which define probability of recovery. FASB Statement No. 121 states that:

> "The term *probable* is used in this Statement consistent with its use in FASB Statement 5, Accounting for Contingencies. Statement 5 defines probable as an area within a range of the likelihood that a future event or events will occur. That range is from probable to remote as follows:
> *Probable*. The future event or events are likely to occur.
> *Reasonably possible*. The chance of the future event or events occurring is more than remote but less than likely.
> *Remote*. The chance of the future event or events occurring is slight."
> (FASB Original Pronouncements, Accounting Standards as of June 1, 1995, Volume 1 FASB Statement of Standards.)

With this context in mind, we find that the recovery of regulatory assets is probable, i.e., likely to occur. During the rate freeze, current ratemaking principles remain essentially intact, and we have reasonable certainty that costs will be covered. Transition cost recovery is now mandated by law and there is no reason to assume that the frozen rates will not result in sufficient headroom to fully recover transition costs. The utilities are already accruing revenues to offset transition costs. For example, the Energy Cost Adjustment Clause (ECAC) and Electric Rate Adjustment Mechanism (ERAM) overcollections for 1996 are already accounted for to offset transition costs, which have the potential to increase the amount of revenues available to provide for transition cost recovery. Moreover, pursuant to D.96-12-077, the rate freeze began this year, which has the effect of allowing the utilities to accrue revenue prior to the beginning of the mandated transition period, thus the recovery period for revenue purposes is five years rather than four.[16] In D.96-12-080, we recognized that under normal ratemaking practices, PG&E's electric rates would have been reduced by approximately 10% to account for the $720.4 million decrease in its authorized revenue requirement. (D.96-12-080, mimeo. at 2.)

Furthermore, § 330(w) states that electrical corporations shall, by June 1, 1997, or earlier, apply concurrently for financing orders from this Commission and for rate reduction bonds from the California Infrastructure and Economic Development Bank. While particular issues associated with rate reduction bonds and transition cost recovery have not yet been addressed, we anticipate that this influx of cash from the asset securitization will have a significant impact on transition cost recovery. Therefore, actual transition cost recovery will thus depend on the outcome of several proceedings, the Power Exchange prices during the rate freeze and market valuation. The total amount of stranded costs related to Diablo Canyon will be authorized in a pending decision in A.96-03-054. The eligibility and magnitude of certain costs for transition cost recovery are yet to be determined and will be addressed in Phase 2 of these proceedings. The proceedings related to the rate reduction bonds have not yet begun. The divestiture proceedings that will reveal the initial market valuation prices for several assets are just in the beginning stages.

As TURN *et al.* points out, there is no reason that we cannot use the annual transition cost proceedings and monthly reports to anticipate and provide for the necessary acceleration of regulatory assets, should it turn out that write-offs appear imminent. It is reasonable to assume that continuing discussions with the Securities and Exchange Commission (SEC) and various accounting organizations would be

[16] As TURN *et al.* point out, in D.96-11-041, we adopted a proxy estimate of 39% of current rates going towards transition cost recovery. PG&E's current revenues are approximately $7.5 billion per year (D.95-12-051, Appendix C). Over 5 years, all things being equal, total revenues would equal $37.5 billion; 39% of that figure is approximately $14.6 billion, which exceeds PG&E's estimates of transition

Footnote continued on next page

necessary before such regulatory assets are considered to be at risk. For example, D.92-12-015 discusses the minutes of a meeting between the SEC and the American Institute of Certified Public Accountants' (AICPA) Public Utilities Committee, which discussed those agencies' view of PBOP accruals qualifying as regulatory assets.

> "Both DRA's [the predecessor to ORA] and the utilities' understanding of what transpired at a meeting between the SEC staff and AICPA Committee are based on incomplete information. However, it is apparent that the SEC has not taken a policy position on what criteria should be used to determine whether a regulatory asset should be allowed or what level of assurance needs to be given by the regulatory agencies.
>
> "We concur with DRA that Commission policy should not be driven by whether or not utilities can record a regulatory asset under Statement 71. Consistent with our position that rate recovery should not be governed by IRS/ERISA requirements, recovery should not be governed by SEC policy or by SEC staff requirements or review." (46 CPUC 2d 499, 521-522.)

While PG&E stated that recent filings before the SEC addressed this issue, these documents were not introduced into evidence. Moreover, although PG&E stated that the overall opinion is that risk and uncertainty prevail, PG&E's witnesses were not able to state how these conclusions were derived. (TR: 184.) Edison, in its original proposal in this phase, does not propose to accelerate the recovery of regulatory assets and has provided a portion of its September 30, 1996 Form 10-Q submitted to the SEC. In its notes to the Consolidated Financial Statements included in that form, Edison concludes: "Despite the rate freeze, SCE expects to be able to recover its revenue requirement based on cost-of-service regulation during the 1998-2001 time period." (Exhibit 11, Appendix D, p. D-2.) This conclusion is based on Edison's ability to flexibly apply revenue to Category II costs, as well as Category I costs; that is, Edison states that it can't allow the Category I account to become too far

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costs, which range from $8.4 billion to $14.1 billion, depending on a market price scenarios ranging from 3.5 cents per kilowatt hour to 1.5 cents per kilowatt hour. (Exhibit 3, p. 7-5.)

overcollected at the expense of Category II costs, which could then trigger the write-offs.

In comments to the proposed decisions, ORA has proposed a compromise approach which should address the utilities' concerns regarding FASB Statement No. 71. We will adopt a 48-month ratable approach to amortizing specific regulatory assets, which may be at risk for write-off because of accounting rules. The determination of which regulatory assets to which this amortization will be applied will be determined after Phase 2 eligibility criteria are resolved. However, if the SEC requires discontinuance of FASB Statement No. 71 for financial accounting purposes, generation-related regulatory assets would remain recoverable through transition cost revenues, to the extent these assets comport with the requirements of § 367.

As the recovery of regulatory assets is accelerated, rate base shall be reduced by the amount of deferred taxes, net of any tax that would be currently due as a result of collecting the regulatory asset.

6.6. The Rate Restructuring Settlement and Section 368

Section 368(h) refers to PG&E's Rate Restructuring Settlement of June 12, 1996 as "an example of a plan authorized by this section." According to PG&E, this means that we must accept its proposal for transition cost acceleration, which is consistent with what was filed in this document. In D.96-12-077, we found that because PG&E's cost recovery plan is substantively different from its June proposal, this example makes it clear that the elements listed in § 368 are not intended to be exclusive nor exhaustive. Furthermore, we stated in that decision that our approval of the cost recovery plans is subject to the following principles:

> "To the extent that any element of the plans or of this decision is inconsistent with § 368 or any other provision of AB 1890, the language of the statute prevails. . . .
>
> "The plans vary considerably in their level of detail. Our approval today covers only the general framework for cost recovery outlined in AB 1890 and the details necessary to launch the program for cost recovery. . . . Our approval of the cost recovery plans does not dispose of or prejudge our resolution of issues still under consideration in those proceedings;

> our decision on those issues will, of course, conform to the statute." (D.96-12-077, mimeo. at pp. 4-5.)

Although PG&E's cost recovery plan and Rate Restructuring Settlement discussed the acceleration of recovery of generation-related regulatory assets, this must be taken in the context of the statute as a whole and conform to the intentions of that statute. As discussed above, allowing generation-related regulatory assets to be accelerated prior to those assets earning a rate of return does not align the interests of shareholders and ratepayers, nor does it conform to the requirement that transition costs should be recovered as expeditiously as possible.

6.7. Should Employee-Related Transition Costs Receive Special Treatment?

We are persuaded that recovery of employee-related transition costs which are currently incurred should be allowed to be deferred, in order to mitigate the utilities' risk of recovering generation-related transition costs. Employees receive protection they might otherwise be lacking because such costs as severance packages, retraining, early retirement, and outplacement which are found to be reasonable are now included in the competition transition charge. In addition, § 375 provides that the costs of employees performing services in connection with § 363 are included as transition costs. Section 363(a) provides, in relevant part, that:

> "In order to ensure the continued safe and reliable operation of public utility electric generating facilities, the commission shall require in any proceeding under Section 851 involving the sale, but not spin-off, of a public utility electric generating facility, for transactions initiated prior to December 31, 2001, and approved by the commission by December 31, 2002, that the selling utility contract with the purchaser of the facility for the selling utility, an affiliate, or a successor corporation to operate and maintain the facility for at least two years. The commission may require these conditions to be met for transactions initiated on or after January 1, 2002. The commission shall require the contracts to be reasonable for both the seller and the buyer."

It is apparent that the Legislature anticipated that certain employee-related transition costs might be incurred prior to December 31, 2001. Despite the contentions of various parties that the presumption was that transition costs would be recovered only during the post-2001 period, the Legislature did not adopt language that provided for the deferral of such costs to the extent that these costs reduce the utilities' opportunities to recover generation-related costs, as it did for implementation costs in § 376. However, because of the concerns for employees delineated in the statute, we will grant the utilities the flexibility to defer recovery of these costs. Consistent with AB 1890, utilities may defer recovery of these costs for later recovery in the period between March 31, 2002 through December 31, 2006.

6.8. Interaction with Rate Reduction Bonds

There has not been a full discussion or development of the record in regard to the interaction of the rate reduction bonds and the transition cost balancing account. Parties have expected that issues addressing rate reduction bonds will be addressed in workshops and in the applications of the IOUs for authority to issue these bonds, including potential ratepayer benefits and the ratemaking mechanisms to prevent costs shifting and to accrue benefits.[17] Workshops were held on March 20 and March 21 on the necessary elements to be included in the financing applications. There are certain critical issues that we believe should necessarily be determined prior to January 1, 1998, including the treatment of bond proceeds and the corresponding treatment of transition cost property.

Section 840(e) provides that:

> "Rate reduction bonds" means bonds, notes, certificates of participation or beneficial interest, or other evidences of indebtedness or ownership, issued pursuant to an executed indenture or other agreement of a financial entity, the proceeds of which are used to provide, recover, finance, or refinance transition costs and to acquire property and that are secured or payable from transition property.

Section 841(e) provides that the Commission has 120 days to process each financing application for rate reduction bonds. It is essential that the details for

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[17] By ruling issued on March 4, 1997 in R.94-04-031/I.94-04-032, ALJ Careaga convened workshops on March 20 and March 21, which were facilitated by the Energy Division. PG&E,

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tracking the bond proceeds and the interaction of the bonds with transition cost property be addressed in such a way so that the expeditious processing of the financing orders is not delayed. We plan to convene workshops in the near future to address these issues.

6.9. Adopted Guidelines in Acceleration of Recovery and Application of Revenues to Transition Cost Recovery

Using the framework outlined above, we find that the Joint Recommendation is flawed in terms of substantive resolution of the issues addressed. The Joint Recommendation accomplishes little beyond attempting to ensure that potential write-offs are avoided and attempting to interpret the statute. We are not persuaded by this interpretation. As we have previously stated, we cannot abrogate our duty to implement the law in the public interest by allowing the parties to interpret the law for us. The terms of the Joint Recommendation do not conform to the statute. As discussed above, the statute specifically states that transition costs should be recovered as expeditiously as possible.

Only the proposal put forward by TURN *et al.* and endorsed by FEA and ORA accomplishes this goal. Moreover, this proposal aligns ratepayer and shareholder interests. By requiring that assets with a higher rate of return be amortized prior to assets with a lower rate of return, more revenues become available for actual transition cost recovery. In response to questioning by the ALJ at oral argument, PG&E acknowledged that the magnitude of dollars that must be collected which are associated with utility generation assets are huge compared to dollars that might be deferred into the post-2001 period. "The rate of recovery of these dollars is such that you really wouldn't know how much needs to be deferred until the very end of 2001 because the dollars are so small relative to the total utility assets. So it does become very difficult to give parties externally or management internally any comfort about what's going to happen." (TR: 687.)

Edison, and SDG&E responded to the questions posed in that ruling with a joint filing on

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The Legislature recognized that the utilities had incurred certain costs in conjunction with their obligations to provide reliable service on a nondiscriminatory basis. These transition costs may therefore be recovered, but only to the extent that they are uneconomic in a competitive market, and furthermore, only to the extent that

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March 14, 1997.

the net costs of above-market assets exceed the costs of below-market assets. While rates are frozen through December 31, 2001 to collect the majority of these uneconomic costs, the rate freeze is allowed to extend through March 31, 2002 to collect certain transition costs related to exemptions, renewable resource program costs, and BRPU settlement costs, with certain additional provisions. Although the rate freeze ends unequivocally on March 31, 2002, certain transition costs are eligible for recovery after this time period. These include employee-related transition costs (which may be collected through December 31, 2006), restructuring implementation costs (which may be collected until fully recovered), and contractually-incurred power purchase and QF costs in place as of December 20, 1995 (which again may be collected until fully recovered). To the extent that the uneconomic costs can be collected prior to the end of December 31, 2001, the rate freeze will end, and presumably rates will drop. In order to help ensure recovery of transition costs, the 1996 ECAC and ERAM overcollections were credited to offset transition costs; in D.96-12-077, we established that the rate freeze began on January 1, 1997. Finally, there is no recognition that recovery of transition costs is guaranteed; indeed, the utilities are at risk for costs not recovered during the rate freeze.

We will not know the extent to which costs are uneconomic until market valuation is completed (by the end of 2001, as required by § 367(b)). In addition, as PG&E points out, the determination of uneconomic generation assets will depend on the role particular units will play in the new generation market (TR: p. 257). Although it may be relatively easy to calculate the sunk costs (which will be addressed in Phase 2), it will be more difficult to determine the portion of sunk costs that become uneconomic. Presumably, there will be some amount recovered in the Power Exchange prices to cover some portion of the utilities' fixed costs. While we cannot anticipate those exact amounts, nor what portion of the economic costs would be recovered, it is crucial that we have the ability to track and review this information. Therefore, we must ensure not only that an adequate balancing account is established, so that we can track the recovery of such costs on an asset-by-asset basis (to ensure that we will know when transition costs are fully collected), but also that adequate review is provided to ensure that only the uneconomic portions of these costs are recovered as expeditiously as possible. Despite the utilities' contentions otherwise, we must necessarily review the utilities' calculations of the uneconomic portions of generation-related transition costs in order to fulfill our duties under the law; e.g., see § 367(b).

We have not addressed the ratemaking treatment for hydroelectric and geothermal assets, in terms of eligibility for transition cost recovery, the appropriate rate of return associated with these assets, and the interaction of transition cost recovery and generation performance-based ratemaking treatment of such assets. We shall address such issues in Phase 2 of these proceedings and in the generation PBR proceedings. We direct the assigned ALJs to coordinate on these issues.

In order to carry out our statutory obligations, we adopt the following guidelines regarding the transition cost balancing account and the order of acceleration:

1. Certain costs which are currently incurred may be deferred. These include restructuring implementation costs (as addressed in § 376), which may be collected until fully recovered, employee transition costs (as addressed in § 375), which may be recovered through December 31, 2006, and generation-related transition costs which may be displaced by collection of renewable program funding (as addressed in § 381(d)), which must be recovered by March 31, 2002 (see discussion below). Other that these exceptions, current costs should be recovered as incurred, as required by current 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 a 48-month amortization 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 is 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.[18] In order to accommodate on-going market valuations and accelerated recovery, the utilities 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 which 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. (TR: p. 267.) 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

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[18] 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.

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 not labeled as transition cost subaccounts, but are merely the sunk costs accounts and subaccounts. This is important because we will establish 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 which 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 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 which 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 over-collections of 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 under-collections 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.

These guidelines will allow us to track and review the transition costs appropriately during the rate freeze period. Adopting this very pragmatic application of the policy established in the newly added PU Code sections does not violate the bargains addressed in AB 1890, as several parties allege; rather, this implementation balances the interests of shareholders, ratepayers, and employees in a manner that is consistent with current ratemaking practices as well as AB 1890.

We decline to give the utilities the flexibility they seek in determining the appropriate market value for purposes of accelerating depreciation to anticipated market value. However, we acknowledge the utilities' concerns with lengthy, protracted hearings and a detailed administrative approach. We will therefore convene workshops to consider how to apply the guidelines adopted in this decision and the potential for streamlining the annual transition cost proceedings.

It is reasonable to require PG&E, Edison, and SDG&E to establish transition cost balancing accounts with a Revenue Account, Current Costs Account, Accelerated Costs Account, and Post-2001 Eligible Costs Account, as all of the utilities now agree. Each utility should establish appropriate subaccounts. Furthermore, all parties agree that, to the extent that headroom is available, revenues are applied first to the Current Costs Account, which should include any currently incurred cost, including costs associated with irrigation district exemptions and renewable programs. Transition costs associated with restructuring implementation costs and employee-related transition costs that are incurred currently may be recorded in the Post-2001 account.

PG&E, Edison, and SDG&E should file and serve pro forma transition cost balancing account tariffs based on these general guidelines and which are in compliance with other Commission decisions in this area.[19] Workshops will be convened in the summer to address specific issues that may arise in the implementation of these tariffs as we work through the Phase 2 issues. We anticipate that workshops also will be convened after the Phase 2 decision is issued to address remaining issues associated with the balancing account tariffs.

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[19] For example, Edison should include language in its tariffs which is in compliance with the SONGS decisions (D.96-01-011 and D.96-04-059) and the Palo Verde decision (D.96-12-083). When we adopt a ratemaking methodology for Diablo Canyon, PG&E should similarly update its pro-forma tariffs. Tariffs should reflect findings adopted in this and any other restructuring-related decisions; otherwise, pro-forma tariffs should reflect the utilities' proposals in various issue areas.

6.10. Tracking Revenues According to Disaggregated Rate Levels

Parties have agreed that the CTC will be calculated as a residual calculation, or the difference between frozen rates and the sum of all rate components, including the Power Exchange price, as discussed above. Under this approach, customers with frozen rates might not benefit from lower Power Exchange prices through lower rates, but would instead receive a benefit because these lower Power Exchange prices would result in increased headroom. We have approved this approach in D.96-12-077, in which we explained that the headroom revenues consist of the difference between recovered revenues at the frozen rate levels (including the reduced rate levels for residential and small commercial customers) and the reasonable costs of providing utility services. As previously stated, it is essential that transition cost recovery be tracked accurately, so that we will know when recovery is complete, and if transition cost obligations are completed before March 31, 2002, the rate freeze may end early.[20] During the Energy Division workshops, described more fully below, participants discussed the requirement in D.96-12-077 which provides that the interim transition cost balancing account include subaccounts for each rate schedule, tariff option, and contract so that revenues may be tracked at this disaggregated level. The purpose of establishing this level of detail is to track the transition cost contributions of the customers of each rate group so that we will know when these groups have paid their fair share of transition costs, pursuant to § 367(e)(1).

During the workshop, participants disagreed with the idea of applying these very specific subaccounts to the final transition cost balancing accounts. The utilities asserted that this kind of detailed tracking is not possible, because the cost allocation information is only disaggregated to the rate group level. The utilities contend that obtaining this information would require them to design a study, install

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[20] Accurate tracking and review will also allow the Commission to be in a position to expeditiously institute the types of proceedings that might be necessary to insure that rates will change when the rate freeze ends.

meters to obtain a representative sample of customers' use, and then collect the data for two years. Workshop participants agreed with the utilities that the current application of Equal Percentage of Marginal Cost (EPMC) methodology does not allocate costs to this detailed level.

In addition, short of some differences in collection periods due to customers on each side of the firewall bearing different exemption costs, participants agree that because of the residual calculation of CTC, there can be no pre-determined CTC obligation by customer class. Workshop participants assert that as long as there are outstanding transition cost obligations, all customers must share these obligations according to their EPMC shares. All customers pay down the aggregate transition cost obligation through the residual CTC recovery in their bills until the aggregate transition cost obligation is paid off. At that point, each group on each side of the fire wall will continue to pay off the accrued exemption amount for its group, until that amount is recovered, but no later than year-end 2001, with the exception of the provision for irrigation district exemptions. Under this interpretation, no customer will satisfy its transition cost obligation sooner than another customer. Parties agreed that transition cost tracking should take place at the rate group level.

This decision adopts a procedure for tracking transition costs and does not address allocation, which will be determined in the unbundling and ratesetting proceeding (A.96-12-009 et al.) We recognize the difficulties associated with tracking transition cost obligations at a level of detail greater than the rate group level, and agree that tracking at the rate group level appears to be the most practical alternative. We will therefore expect utilities to track transition cost obligations and payments at this level of detail. Section 367(e)(i) requires that transition costs be allocated among the various classes of customers, rate schedules, and tariff options to ensure that costs are recovered "in substantially the same proportion as similar costs are recovered as of June 10, 1996, through the regular retail rates of the relevant electric utility…" We are satisfied that tracking CTC revenues and transition cost recovery at the rate group level, together with the rate unbundling process and the implementation of the fire wall memorandum accounts should ensure that the requirements of § 367(e) (1) are met. Rate groups are the fundamental units for which marginal cost revenue responsibility and allocated revenue are determined. As such, rate groups are aggregations of related tariff schedules (default and optional), and disaggregations of customer classes. For example, the large power customer class consists of several rate groups. Issues related to allocation of transition costs and any potential for certain customers to pay off transition cost obligations faster than others will be addressed in our unbundling and ratesetting proceeding, A.96-12-009 *et al.*, and we direct the utilities to address these issues in crafting and updating CTC tariffs for direct access and full service customers once a decision is rendered in that proceeding.[21]

7. Federal Jurisdictional Issues and Western Contract 2948-A Arrangements

PU Code § 369 reads as follows:

> "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. However, the obligation to pay the competition transition charges cannot be avoided by the formation of a local publicly owned electrical corporation on or after December 20, 1995, or by annexation of any portion of an electrical corporation's service area by an existing local publicly owned electric utility.
>
> "This section shall not apply to service taken under tariffs, contracts, or rate schedules that are on file, accepted, or approved by the Federal

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[21] By ruling issued January 31, 1997 in A.96-12-009 *et al.*, the assigned ALJ provided that the ratesetting implications of the virtual direct access option would be addressed in that proceeding. The following example may help to illustrate the issue involved: Under frozen rates, one customer may consume energy primarily in off-peak periods. In these periods the Power Exchange price is low and headroom is larger, meaning that a significant portion of this customer's bill would be applied to CTC revenues. Another customer may consume more energy on peak when the Power Exchange price is higher. A higher Power Exchange price reduces the amount of revenues available for the CTC, so that the CTC payment is only a small percentage of this customer's total bill.

> Energy Regulatory Commission, unless otherwise authorized by the Federal Energy Regulatory Commission."

This last sentence has been the subject of some dispute. PG&E discussed what it characterized as a "common" instance of departing load supply arrangement as that where a customer is able to take increased deliveries of power from the Western Area Power Administration (Western), under a Contract 2948-A arrangement, with the exceptions that Western power delivered to Bay Area Rapid Transit (BART) pursuant to § 701.8 and Western deliveries to the University of California(UC) Davis at the contractual level in effect on May 31, 1996 are exempt from CTC, pursuant to PU Code § 374(b) and (c). FEA and Sonoma County object strongly to this treatment and state that § 369 prohibits the application of CTC to federal government customers of Western without specific approval by FERC.

FEA states that these are long-standing electricity supply arrangements and are presently and will continue to be in the future executed exclusively pursuant to contracts filed with and approved by FERC; that § 369 mandates that CTC imposed in connection with FERC jurisdictional matters must be authorized by FERC; and that therefore, PG&E may not impose such CTC without FERC approval.

PG&E argues that the last sentence in § 369 is merely a "savings" clause, which recognizes FERC's jurisdiction over wholesale power transactions and transmission services, i.e., that transition costs can be collected in the form of a FERC rate only if FERC authorizes the utility to do so. PG&E further asserts that this understanding was quite clear and understood by the parties participating in the lengthy discussions and negotiations that led to language adopted in AB 1890, including § 369. PG&E argues that because specific language singles out two particular Western customers, BART and UC Davis, in § 374 (b) and (c), there can be no extension of such particular exemptions to other Western customers. Indeed, if such was the intent, there would have been no reason for § 374 to reference BART and UC Davis. Finally, PG&E contends that because the FEA and Sonoma County were not involved in the drafting process, they have little basis on which to offer their alternative reading of § 369.

PG&E states that taken to the extreme, FEA's reasoning could lead to the conclusion that § 369 would prohibit all transition cost recovery, since all electric consumers in California will be receiving transmission services upon implementation of the ISO tariff that will be subject to tariffs, contracts, or rate schedules that are on file, accepted, or approved by FERC.

FEA contends that it is not suggesting that it was the Legislature's intent to exempt all customers switching from PG&E service to Western supply service provided under Contract 2948-A. FEA states that § 369 is not intended to exempt any user from the CTC, but that any CTC that is imposed in connection with FERC-jurisdictional matters must be authorized by FERC. FEA asserts that § 374(b) and (c) provide BART and UC Davis with absolute exemptions, so that they will not be subject to CTC. Finally, FEA argues that there is a fundamental difference between the implication of taking new services under FERC tariffs after December 20, 1995 and taking FERC jurisdictional service for as much as 30 years prior to this date. That is, FEA recognizes that a customer who was taking PG&E service subject to CPUC jurisdiction prior to December 20, 1995, and then displaced that service with third-party generation which was wheeled to the customer under a FERC-jurisdictional tariff, may certainly be subjected to CTC under this Commission's jurisdiction. This is consistent with § 369. However, FEA contends this Commission does not have jurisdiction to impose CTC on customers who have been taking service under a FERC-jurisdictional contract for several years prior to the Preferred Policy Decision, when those customers increase their delivery of Western power, even if that increase is after the date of the Preferred Policy Decision, since that contract allows customers to change the mix of power delivered by PG&E and Western. Finally, FEA states that there is no authority that would support the assertion that the ability to interpret statutory language requires active involvement in the process of drafting that language.

Sonoma County also receives its allocation of federal power under Contract 2948-A and subsidiary agreements, which, it alleges, are part of a complex, integrated power supply and transmission arrangement that benefits Western, Sonoma, and

PG&E, the benefits of which have been determined both by Federal agencies and in court. The contracts for the subsidiary arrangements are also on file with FERC. These contracts all specifically contemplate that PG&E will deliver increases in Western allocations to those retail and wholesale customers of Western without compensation for purportedly displacing PG&E sales.

Similar to FEA's argument, Sonoma County believes its right to this exemption is distinguishable from the average PG&E retail customer that might in the future receive FERC-regulated transmission service for an alternative source of power supply, because Sonoma County's right to purchase the Western allocation derives from federal law. In addition, Sonoma County contends that Contract 2948-A involves more than just transmission service to a potentially infinite group of retail customers; the interrelationship of the power supply, support, transmission, and other arrangements of Contract 2948-A results in a limitation on Western's ability to provide service to any other than a select group of customers, whose eligibility for service depends on federal law and federal regulation. Moreover, the amount of energy and capacity available for sale is limited to a coincident customer demand of 1152 MW.

Sonoma County agrees with FEA's assessment of the BART and UC Davis exemptions and suggests that such language must be interpreted as a direct reaffirmation of the Legislature's intentions in § 701.8, in which BART is allowed to reduce its electricity cost through the purchase and delivery of preference power and § 374(c) which also references an existing relationship. Sonoma County also disputes PG&E's statutory interpretation, stating that trusting "PG&E's interpretation of the language because 'PG&E was there and others were not' sheds little light on how to apply the language actually written into the statute…. " (Sonoma County's Brief, p. 25.) Sonoma County therefore requests that we ensure that PG&E include terms and conditions in its tariffs which recognize that PG&E will not collect a CTC from retail customers with respect to loads served with an allocation from the Western under Contract 2948-A.

PG&E points out the public policy interest in ensuring the principle of nonbypassability. The utilities want the CTC to be nonbypassable to reduce the risk that they will not be able to recover as much transition costs as possible during the rate freeze period. Ratepayers (residential, commercial, and industrial) want CTC to be nonbypassable to end the rate freeze as soon as possible and to avoid shifting of transition cost responsibility. PG&E contends that the last sentence of § 369 does not extinguish the obligation to pay CTC, but recognizes that PG&E may use the FERC transmission delivery tariff or contract used by the consumer as a mechanism for collection of CTC only if FERC authorizes it.

PG&E further contends that the critical factor is that PG&E is not attempting to collect the CTC through a surcharge on service taken under FERC tariffs and would not impose CTC on Western (but on the customer) and would not result in establishment of CTCs that would be included in Contract 2948-A, and therefore does not set FERC rates. According to PG&E, the CTC will be charged under a tariff that applies to retail customers that are subject to this Commission's jurisdiction by virtue of their partial status as a PG&E retail customer. PG&E further asserts that it is not a party to the sales agreement between Western and its customers and those Western-customer agreements are not on file with FERC because Western is not subject to FERC jurisdiction and FERC does not have jurisdiction over sales of power at retail.

The Farm Bureau, CIU *et al.*, and Edison support PG&E's position and state that there is no reason to assume that § 369 exempts these Western allocations from the CTC. The Farm Bureau suggests that AB 1890 does not provide for an exemption within § 369, but that the remedy may lie in legislative relief.

7.1. Discussion

We have addressed analogous situations in D.96-11-041:

> "No exemption seems necessary. An important point here is that the reduction in load is not permanent, but is part of normal and continuing variation in the federal deliveries and residual PG&E service. . . . these customers do not fall within the definition of departing load, since they continue to be PG&E customers under the same arrangements that governed their service from PG&E before December 20, 1995, and any reductions in load that fall within the existing arrangements are not 'subsequently served with electricity from a source other than PG&E.' This conclusion may not apply if the existing arrangements were altered

> in a way that reduced service from PG&E and substituted service from another source." (D.96-11-041, mimeo. at pp. 15-16.)

No exemption is necessary in PG&E's tariffs, because the definition of departing load does not apply to Western customers who are merely shifting their allocation of federal preference load and PG&E load in a manner contemplated under the existing contract. While no exemption is necessary in this instance, PG&E should clarify the tariff language included in its Preliminary Statement to further define "departing load" in accordance with this decision. While as a matter of public policy, we believe that to the extent possible transition cost responsibility should be subject to as few exemptions as possible, FEA and Sonoma have raised important jurisdictional concerns. Under the scenarios described, Western customers are exempt from CTC. According to a plain reading of § 369, FERC must authorize a CTC mechanism as it applies to service taken under contracts, tariffs, or rate schedules that are on file, accepted, or approved by FERC. Therefore, this Commission cannot authorize a CTC for this service. However, a customer outside of these specific federal preference power contractual agreements or other similar agreements covered by § 369, who was taking PG&E service subject to CPUC jurisdiction prior to December 20, 1995 and then displaced that PG&E service with third-party generation, which is wheeled to that customer under a FERC-jurisdictional tariff, will be subject to CTC. In addition, to the extent that a CTC is imposed by FERC, we intend to develop a process to adequately account for these funds to offset transition cost recovery and to make any necessary adjustments to the firewall memorandum accounts.

In comments to the proposed decisions, PG&E requests that we clarify the standards for applying the provisions of § 369, including how CTC should be applied to, for example, new Western customers, existing customers at new sites, customers that resell Western power, military base closures, departing customers, Western customers that buy from someone else, and customers served under other FERC-jurisdictional contracts. We do not intend to provide a definitive list of which contracts are or are not subject to the provisions of § 369. We expect that parties should be able to apply the provisions of the law. To the extent that there are disputes that cannot be resolved through the dispute resolution process discussed herein, parties have the opportunity to file complaints or the Motion for Evaluation of Departing Load Statement, described below. Specific comments on this issue have been filed by the City and County of San Francisco. Pursuant to Rule 77.4, we will not address new factual assertions brought before us at this time. These facts, as noted by the City and County of San Francisco, are not part of the record and these issues are not before us as part of this proceeding.

We take this opportunity to further clarify that interpretational arguments amounting to: "We were there and therefore, only we know the Legislature's intent" will not be accepted. The Legislature could certainly have drafted the language included in § 369 to ensure that limited purposes and special considerations would be accommodated. Obviously, the Legislature did not do so.

8. Stipulations and Tariff Issues Related to Terms and Conditions

Parties requested time at the first day of evidentiary hearings to hold an informal workshop to address various tariff issues which they felt could lead to certain stipulations. In addition, several tariff issues were resolved at workshops convened by the Energy Division, and where issues were not resolved, substantial progress was made in narrowing the focus of the contentious issues. These tariff workshops are very valuable in our efforts to implement the complex world of electric restructuring. We congratulate the Energy Division and the participants on their successful resolution of issues and will hold other such workshops in the near future. Such settings are preferable to protracted hearings and more effective at allowing parties to discuss and resolve differences. We adopt the stipulations and consensus recommendations supported by all parties. We expand the application of certain recommendations so that additional information is provided to consumers, as we discuss below. As we move forward in implementing the new competitive generation framework, it is crucial that consumers have easily accessible and understandable information available to them, so that each customer can make informed choices.

8.1. Stipulation Regarding Market Rate Forecasts

As discussed above, primarily because of the rate freeze, CTC will be determined on a residual basis. This is true for bundled customers, direct access customers, and departing customers. This concept will be more fully developed in the unbundling proceedings. Therefore, parties have agreed that 2.4 cents per kilowatt hour should be used to approximate the market clearing price for the limited purpose of developing an estimate of the total transition cost level which is applicable for 1998. This number may be important for developing the rate reduction bond applications, which are also addressed in AB 1890.

8.2. Energy Division Workshops

The major issues regarding the terms and conditions of exemptions and departing load were either agreed to at the informal workshop or in Energy Division workshops. Parties generally agree that a uniform approach is preferable for all three utilities. Several issues were stipulated to at hearings and more detailed agreements were discussed at the workshops, including the following agreements: 1) to the extent possible, the billed CTC will be based on metered consumption, and 2) one of the options for determining the load of departing customers may include reliance upon third-party metering, so long as a verification of that meter reading is provided, and that each party shall bear its own costs for any verification process of those meter readings.

Section 369 provides that the CTC is applicable to all existing and future customers. Within this broad applicability for CTC there are three general categories of customers: 1) continuing utility full service customers; 2) customers that continue utility delivery services but obtain all or part of their energy from a provider other than the jurisdictional utility (direct access customer); and 3) customers that obtain all or part of their energy and delivery services from a provider other than the jurisdictional utility (departing load customer). PG&E, Edison, and SDG&E have indicated that tariffs identifying the CTC calculation for full service customers and direct access customers would be filed in the unbundling and direct access proceedings.

8.2.1. Billing Determinants, Metering, and Rate Basis

Parties reached agreement on a departing load customer's ability to provide information from third-party metering to the utility as a basis for adjustments to CTC payment calculations. Participants discussed this stipulation and reached further agreement on metering and rate basis (i.e., the rate schedule to be used to calculate the CTC for departing customers) issues and how tariff language should reflect these agreements. First, parties discussed the various utility-proposed defaults for applying billing determinants to calculate a customer's CTC; for example, whether to use an historical average or current metered data. SDG&E endorses using current metering information when available. PG&E prefers to use historical over current information, and Edison prefers current information but would settle for using historical metering information. In the workshop, all parties agreed that it would be inappropriate for a utility to require current metered information and that the optimal approach is to let the customer select the billing determinant. We agree with participants and will approve the updated modifications to utility tariffs which reflect this understanding (included as Attachments 7 and 8 to the Energy Division's workshop report).

Participants also agreed that customers could change the rate basis used in their CTC calculation by providing current metered information to demonstrate that, if they were still taking utility service, they would be under a different rate schedule. We agree that this is reasonable. Although customers are under a rate freeze, they are not prohibited from moving from one frozen rate schedule to another. Since this option is available to full service customers, it should also be available to direct access and departing load customers. We therefore direct the utilities to include this option in direct access tariffs and full service tariffs, to the extent necessary, with the understanding that this particular language may be subject to adjustment based on findings in the direct access and unbundling proceedings.

Another metering issue discussed in the workshop was specific tariff language indicating that metering would be used for these purposes only if it was reliable. Non-utility parties believed the utilities' proposed language relinquished the determination of reliability to the utilities. Participants agreed on language indicating that metering would be deemed reliable pursuant to standards in tariff Rule 17 (for PG&E and Edison; Rule 18 for SDG&E), or other standards that we might eventually adopt. For now, we find that it is reasonable to determine metering reliability for CTC purposes based on Rule 17 standards for PG&E and Edison and on Rule 18 standards for SDG&E. However, we note that there is some confusion regarding whether this standard would be the same for direct access and full service customers. In PG&E's revised tariffs this language is included only in the section addressing CTC for departing load customers. In contrast, Edison's tariffs include this language in the section of the tariffs applicable to all customers. To the extent that a customer could receive a CTC-related benefit by utilizing third-party metering, it is equitable to provide the same metering options all customers. Therefore we agree with Edison's inclusion of this language in the section of tariffs applicable to all customers. PG&E and SDG&E shall incorporate this provision in their tariffs, again, with the understanding that this particular language may be subject to adjustment based on findings in the direct access and unbundling proceedings, such as, the establishment of specific metering standards.

8.3. Applicability of CTC

As discussed above, § 369 provides that CTC is applicable to all existing and future customers. While the tariffs filed in this docket have focused on departing load customers, each utility took a different approach to the design of these tariffs. PG&E and Edison filed the most detailed departing load tariffs. For example, Edison's tariff begins with a statement of the purpose of the CTC and then of the broad applicability of CTC. Following this is a section regarding CTC calculation, which provides the methodology for calculating the CTC for various kinds of customers, including those customers provided particular terms or treatment by assorted code sections. This section is where Edison details exemptions. Following this is a section detailing the CTC terms and conditions specific to departing load customers. This includes language regarding the obligation to provide notice, sign an agreement to pay CTC, and be subject to potential penalties and associated curative measures unique to CTC for departing load customers.

PG&E used a different approach which can best be understood by comparison with the Edison approach. PG&E's entire tariff applies only to departing load customers. Because the PG&E tariff does not contain a section of generalized CTC language useful for all customers, PG&E would presumably have to repeat much of the language in its departing load tariffs in tariffs for direct access and full service customers. One other notable difference between the PG&E and Edison tariffs is that Edison's language regarding special treatment of particular customers (as may be required by various code sections) is more detailed and provides important explanations of the PU Code. In contrast, the PG&E tariffs summarize the PU Code exemptions in two or three sentences and cite the PU Code. Presumably, a customer needing more information would be required to seek more detail in the PU Code.

SDG&E provided representative tariffs that it proposed to add to its tariffs for each rate schedule. These provide a description of CTC and a summary of exemptions that is more detailed than that provided by PG&E and less detailed than that provided by Edison. SDG&E's lack of notice provisions, penalties and curative measures and other language specific to departing load customers reflects SDG&E's proposal that unique terms are not necessary for departing load customers because it contends that existing tariff provisions for nonpayment of bills are adequate.

A primary consideration in evaluating tariff format issues is determining which format is likely to enhance the usefulness of the tariffs for customers. Customers cannot generally dedicate extensive time and effort to evaluating tariffs, so it is reasonable to attempt to ensure that the tariffs are as customer-friendly as possible. This is likely to be particularly important in the future, as competitive options become a reality and as customers take a greater interest in comparing service options. Tariffs should be designed so that the customer can easily understand the costs and implications of choosing various available service options. Another benefit of having all CTC tariffs in one place is that it eliminates the need for extensive cross-referencing to understand the implications of choosing various service options.[22] Providing CTC tariffs for full service, direct access, and departing load customers in the same area of the tariffs will help the customer assess the way its CTC calculation and terms might change under the various service alternatives. It is prudent to put this language and all generalized CTC language in a general tariff section applying to CTC for all customers, followed by more specific language delineating particular requirements for full service customers, departing load customers, and direct access customers. Edison's tariffs are a useful model and begin with language necessary for all customers.

Therefore, we direct PG&E and SDG&E to revise their terms and conditions tariffs according to Edison's model and the requirements outlined in this decision.; i.e., the tariff formats should include all generalized CTC tariff language in one CTC tariff having broad applicability and be followed with the tariffs specific to departing load customers, utility service and direct access customers.[23] PG&E and SDG&E should also reflect the language in Edison's tariff section titled "CTC calculation." To the extent that PG&E and SDG&E must modify Edison's language to reflect utility-specific exemptions or modifications, such modifications should reflect the detail and approach used by Edison. We also note that Edison's definition of departing load is not included in the departing load tariffs, but in its Rule 1 definitions. In addition to adhering to the General Order 96-A requirements, PG&E, Edison, and SDG&E should also provide this definition at the beginning of its

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[22] Design of CTC tariffs will be an important consideration in this customer analysis. For example, a customer considering an alternative energy provider is likely to know its current energy rate is because this is provided in the bill. The customer would also presumably have an idea of the cost of energy from an alternative provider because this knowledge is likely to be what causes the customer to consider the alternative provider. What the customer needs to understand is the way its CTC charge and associated terms might change if it utilized the alternative energy provider.

[23] We understand that utilities planned to file CTC tariffs for utility service and direct access customers in the unbundling and direct access proceedings. These tariffs should also be filed in this docket.

departing load section. In revising or developing tariffs as ordered here, utilities should abide by the following principles: 1) Utilities should work together to achieve the highest degree of uniformity practicable; 2) When tariff language is based on a utility proposal that has yet to be approved in the direct access or unbundling proceedings, the tariffs should reflect the utility proposals and this should be clearly stated. The full service and direct access CTC tariffs may require later modification to reflect decisions adopted in other proceedings. These modifications may be handled by augmented advice letter procedures, as we discuss below, or be addressed in a workshop. Additional guidance will be provided by ruling.

8.4. Exemptions from CTC

PU Code §§ 372 - 374 address exemptions from transition cost recovery for specific customers, customers' end-uses, or customer classes.

Some parties believed that two types of exemptions were not adequately addressed in the pro-forma tariffs. On December 3, 1996, parties reached a stipulation regarding utility reflection of the PU Code § 372 exemption for onsite and over-the-fence generation committed to after December 20, 1995. During the terms and conditions workshop process, utilities updated their tariffs with language that acceptably reflects these exemptions. Essentially, this language better clarifies that: 1) the §372 (c)(1) exemption provided for self-generation units is for units whose construction had not commenced before December 20, 1995, as opposed to units whose construction had begun before this date, for which other exemptions apply, and 2) the exemption provided in § 372 (c)(2) applies only to over-the-fence arrangements between unaffiliated parties, rather than affiliated parties, for whom exemptions are provided in § 372 (a)(1).[24] We agree with these recommendations and clarifications to the tariffs, because they are consistent with the law.

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[24] Section 372(c) provides, in relevant part, that "[t]he Commission shall authorize, within 60 days of the receipt of a joint application from the service utility and one or more interested parties, applicability conditions as follows:

Footnote continued on next page

8.5. Fire Wall and Exemptions

Section 330(v) establishes a fire wall as follows:

"Charges associated with the transition should be collected over a specific period of time on a nonbypassable basis and in a manner that does not result in an increase in rates to customers of electrical corporations. In order to insulate the policy of nonbypassability against incursions, if exemptions from the competition transition charge are granted, a fire wall shall be created that segregates recovery of the cost of exemptions as follows:

"(1) The cost of the competition transition charge exemptions granted to members of the combined class of residential and small commercial customers shall be recovered only from those customers.

"(2) The cost of the 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 those customers. The commission shall retain existing cost allocation authority provided that the fire wall and rate freeze principles are not violated." (See also PU Code § 367 (e)(1).)

Therefore, the exemptions delineated above necessitate the establishment of the fire wall to ensure that no cost-shifting occurs and may lead to a 3-month extension of the collection period for the recovery of certain, specific exempted costs from the appropriate side of the fire wall. The fire wall is thus established to address revenue shortfalls due to exemptions.[25]

Section 367(a)(5) provides that to the extent that CTC-eligible costs are not recovered prior to December 31, 2001, due to revenue loss from irrigation district

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"(1) the costs identified in Sections 367, 368, 375, and 376 shall not, prior to June 30, 2000, apply to load served onsite by a nonmobile self-generation or cogeneration facility that became operational on or after December 20, 1995.

"(2) The costs identified in Sections 367, 368, 375, and 376 shall not, prior to June 30, 2000, apply to load served under over the fence arrangements entered into after December 20, 1995, between unaffiliated entities."

[25] Pursuant to § 374(b), the fire wall does not apply to BART exemptions. CTC costs due to exemptions for BART will be paid for by all remaining PG&E customers.

exemptions only, the utilities are allowed to extend its collection period (and therefore, the rate freeze period) to March 31, 2002, provided that, subject to the fire wall restrictions, only $50 million of this category of costs are eligible for recovery.

Therefore, the CTC amounts that would otherwise have been paid by exempt customers must be tracked according to the type of exemption and by class (i.e., large vs. small in compliance with the fire wall). The memorandum accounts and methodology that have been proposed by PG&E and Edison in Exhibits 7 and 10, respectively, are acceptable for tracking these exemptions. SDG&E should include similar language in its tariffs to implement this requirement.

8.6. Issues Regarding Exemptions

In its Phase 1A opening brief, MID disputes PG&E's intention to collect a payment for public benefits programs from departing customers who begin taking exempted load from an irrigation district. MID believes that if PG&E is allowed to implement this practice, those customers will be paying twice for the same public benefits programs. Because the allocation and collection of nuclear decommissioning charges and public purpose benefits charges are not being considered in this proceeding, MID should raise this issue in the unbundling and ratesetting proceeding, as directed by ALJ ruling issued on January 31, 1997.

PG&E states that imputed post-2001 lump-sum amounts must be determined by December 31, 2001 for exempt non-irrigation district loads during the period from January 1, 2002 to March 31, 2002. PG&E further states that irrigation district customers will retain responsibility for making their own post-2001 CTC payments.

MID believes that a plain reading of § 374 and the sunset provision stated in § 374(a)(4) is that after March 31, 2002, a departing customer would not be exempted from transition costs; i.e., if MID has not utilized its 75 MW of load for which the exemption was provided by the sunset date, any remaining portion is no longer available as exempt load.

PG&E, on the other hand, states that the statutory language means that the exemptions of costs identified in §§ 367, 368, 375, and 376 expires as of March 31,

2002. Therefore, any irrigation district customers are no longer exempt from transition costs and must begin making their own payments for transition costs remaining to be collected after March 31, 2002. This will include employee-related transition costs (§ 375), restructuring implementation costs to the extent not recovered from any other source (§ 376), and transition costs related to power purchase agreements, which extend over the life of the contract.

We agree with PG&E. A plain reading of the statutory language does not indicate that any of the 75 MW are no longer available as exemptions, but that, in fact, these customers are no longer exempt from any transition costs accruing in the period after March 31, 2002. While PG&E has referenced Merced's position with a discussion of the understanding of the parties during the drafting of AB 1890, such a discussion is irrelevant for these purposes. Again, we reiterate that at this point, the intentions and understanding of the parties in drafting the legislation does not matter; it is the language of the statute that is relevant. Furthermore, MID is incorrect in assuming that PG&E may seek to recover the $50 million from exempt customers; rather, the utilities may recover a maximum of $50 million in exempt costs from all other large customers during the January 1, 2002 through March 31, 2002 time period, a period during which the irrigation district customers are still exempt from these costs.

8.6.1. Dispute Resolution

MID is also concerned regarding PG&E's tariff language that provides that the utility will make the initial determination of eligibility for exempt status. MID states that PG&E's requirements raise unnecessary hurdles to competition by requiring the customer to provide notice to PG&E of its intent to claim exempt status and by imposing the responsibility on the customer to file a motion for the evaluation of departing load CTC statement with the Commission, if the customer disagrees with PG&E's assessment. MID recommends that because PG&E has an economic interest in finding no exemption, the utility should be required to challenge a claim of exemption by filing a motion with the Commission, and that the irrigation district supplier should be entitled to respond on behalf of the challenged customer.

PG&E states that the notification procedure is necessary, so that only those customers that are so entitled receive exemptions and so that adequate records can be kept for fire wall accounting purposes. PG&E's proposed tariffs require that within 20 days after receipt of a departing load CTC statement, a departing load customer may file a "Motion for Evaluation of Departing Load CTC Statement" at the Commission in R.94-04-031/I.94-04-032.

Conceptually, we agree with PG&E. However, as we found in D.96-11-041, PG&E's proposed process is cumbersome. We will adopt the same procedures for PG&E, Edison, and SDG&E which we found reasonable for PG&E in D.96-11-041. If a departing customer believes that the departing load statement does not comply with the terms and conditions of the tariffs and related decisions, it should notify the relevant utility in writing of the grounds for its belief within 20 days after receiving the departing load statement. If the utility does not accept the customer's position, it should respond in writing within 5 days after receiving the customer's notification. The utility and the customer should then confer to attempt to resolve the differences. If necessary, the parties may also consult with Energy Division staff to attempt to achieve resolution. If no resolution is reached within 10 days, the customer may then file the motion described in the proposed tariffs. The utility and the customer may agree to extend this 10-day period to allow for further negotiations or other resolution techniques. PG&E, Edison, and SDG&E should amend their tariffs to reflect these provisions.

8.7. CTC-Related Penalties

An area of transition cost tariff proposals that resulted in extended dialogue among workshop participants was provisions for penalties applied to departing customers for failure to provide notice and failure to pay CTC. For the most part, Edison derived its departing load tariffs from the PG&E tariffs, so their initial tariff proposals were similar. SDG&E disagreed with using unique penalties for transition costs for departing load customers. SDG&E prefers to rely on the penalty mechanisms already included in its tariffs for transition cost penalties.

We disagree. First, transition costs for departing load are distinguishable from other utility charges in that the utility has limited or no ability to threaten termination of service if the customer fails to meet its obligations. It is reasonable to develop unique penalty procedures to ensure that departing load customers cannot bypass transition costs and increase the transition cost burden on full service and direct access customers. Second, departing load transition cost charges are of a much greater magnitude than would customarily be associated with a few months of missed bills. It is reasonable to develop special procedures that allow the customer enhanced opportunities to cure the problem. For these reasons, we will order SDG&E to mirror the PG&E and Edison tariffs regarding the departing load transition cost penalties, modified as discussed below.

8.7.1. Failure to Provide Notice of Departure

Participants also discussed whether there is any reason to utilize a different penalty procedure for customers who fail to provide notice of departure as opposed to customers who fail to make CTC payments. Workshop participants agreed that different penalty procedures are appropriate and that the Edison and PG&E proposals for penalties for failure to provide notice are adequate. We approve this consensus agreement, authorize PG&E and Edison to implement the departing load penalty for failure to provide notice of departure as presented in Attachments 7 and 8 of the Energy Division workshop report issued on January 24, and also order SDG&E to draft tariffs to include the departing load penalty for failure to provide notice of departure.

8.7.2. Failure to Pay CTC

PG&E and Edison proposed a penalty for departing load customers who do not pay CTC which involved issuing a notice to cure if payment is not received by the end of the payment grace period. If the customer does not remit the missed payment within 20 days of the notice to cure, PG&E and Edison would immediately pursue the lump-sum payment described below. At the beginning of evidentiary hearings, ORA indicated that it disagreed with these utility procedures but would set them aside for discussion in the transition cost terms and conditions workshop. During the workshop, ORA introduced a proposal that would add another stage between a customer's failure to comply with the notice to cure and the utility's pursuit of the lump-sum payment.

In this so-called two stage approach the utility would respond to the customer's failure to satisfy the notice to cure by issuing a notice to provide payment and deposit. The customer would have the opportunity to respond to this notice by becoming current on its missed CTC payments and providing a deposit in the amount of two times the missed payments (i.e., four monthly CTC payments within 30 days of the notice to provide payment and deposit. If the customer provided this payment and deposit to the utility, the matter would be resolved. If the customer failed to provide this payment and deposit by the end of the 30-day grace period, the utility would then pursue the lump-sum payment. The net effect of the ORA proposal is that the customer that fails to meet the original notice to cure is provided a second remedy at a cost much lower than the cost of the final lump-sum payment. This two-stage approach also allows the customer an additional 30 days before facing utility pursuit of the lump-sum penalty.

Workshop participants agreed that the two-stage approach is preferable to the original utility proposals. We agree, the most persuasive reason being that it provides an additional cushion for human error. Departing load customers may include large industrial customers, but may also include residential and small commercial customers who opt out of the utility's delivery system. Customers who forget to make a CTC payment or fail to arrange payment of bills during an extended vacation or sick leave should be provided a more relaxed initial penalty before the utility pursues a penalty as dramatic as the lump-sum payment. Therefore, PG&E, Edison, and SDG&E shall revise their tariffs to reflect this modified penalty process, with modifications to the lump-sum payment as detailed below.[26] We order SDG&E and Edison to implement the extended grace periods for purposes of the departing load transition cost penalty for failure to pay CTC. (See Energy Division's Workshop Report, Table 1.)

Certain details must be resolved in order to implement the two-stage penalty. First, we recognize that the utilities might have differences in the way they treat customer deposits, pursuant to Rule 7 of their existing tariffs. An example is that PG&E's computation of interest on deposits differs from that of SDG&E and Edison in the frequency of the compounding. In general, these differences have no substantive policy implications, and the utilities should therefore implement this penalty with the understanding that they will treat the deposit with the same rules already established by existing Rule 7.

Second, one understanding reached during the workshop was that the two-stage penalty procedure would be available to the customer only for the first instance in which the customer fails to pay CTC without response to the notice to cure. We agree that this is a reasonable approach. Upon being reminded of the importance of meeting the CTC obligation during the first invocation of the two-stage penalty, the customer should gain an understanding of the need to stay current on its transition cost obligations.

Finally, the workshop report reflects an agreement among participants that, having collected a deposit once using the two-stage penalty, the utility could apply deposit amounts toward CTC payments in the event the customer again fails to meet CTC payments. However, we find that this agreement violates Rule 7 provisions for the appropriate use of deposits. We therefore clarify that the utility cannot draw on a customer's deposit to meet missed CTC payments, with the following exceptions. Edison's Rule 7 allows for the application of deposits to the

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[26] We note that a uniform grace period is required for purposes of this penalty only and clarify that this change in grace period will not apply to any other aspect of the utilities' tariffs.

customer's closing bills at the time the customer discontinues taking service from the utility. A parallel interpretation should be allowed for Edison so that deposits may be applied to outstanding departing load transition costs at the end of the transition period. To the extent that PG&E's and SDG&E's Rule 7 tariffs allow for such application of deposits to closing bills, PG&E and SDG&E should also allow for application of deposits to outstanding Departing Load CTC at the end of the transition period.

8.7.3. The Lump-Sum Payment as Penalty

The utilities have proposed a lump-sum payment to be applied in the case of penalties and which is also to be collected on March 31, 2002, in lieu of the monthly obligation. We discuss the penalty provision first.

The Farm Bureau has expressed concerns that the lump-sum payment associated with the departing load penalties for failure to provide notice or pay CTC is unnecessarily large, and is linked to a customer's total bill rather than only the uneconomic portion of the bill. Therefore, the Farm Bureau believes that linking the lump-sum payment to these additional amounts (i.e., the entire bill) unfairly penalizes the departing customer. We use this opportunity to address concerns not only that calculation of the lump sum may be inequitable, but that the lump-sum payment requirement could be anticompetitive.

Used as a penalty, we do not believe that the lump-sum payment is anticompetitive. We note that a departing load customer has ample opportunity to avoid the lump-sum penalty by providing notice to the utility and meeting its monthly transition cost obligations. In addition, we have now required that the tariffs provide a reasonable opportunity to correct the situation to avoid the lump-sum penalty. Therefore, we do not believe that it is reasonable to incorporate the lump-sum penalty into any decisions to utilize alternatives to utility distribution and energy services. This would be analogous to basing a cost-effectiveness analysis on the assumption that the customer would fail to meet simple obligations such as paying its bills. In general, we find this to be an unreasonable assertion. Customers that choose to utilize alternative energy and distribution services are likely to be aware of what their obligations would be if they pursue these alternatives, including their obligations to provide notice and meet monthly transition cost obligations.[27] Therefore, we conclude that, used as a last resort, the lump-sum payment is unlikely to be anticompetitive.

However, we agree that there is an equity issue associated with the lump-sum payment. If the lump sum represents an amount greater than the customer's actual net present value transition cost obligation at the time that the penalty is levied, that customer pays more than its fair share of transition cost obligation. If the lump sum is an amount less than the customer's net present value transition cost obligation at the time the penalty is levied, the customer would pay less than its fair share of transition costs, leaving other customers to pay the remainder. The optimal outcome is for the lump-sum penalty to reflect the best estimate of its remaining transition cost obligation when the penalty is levied.[28] If this outcome can be achieved, it also serves as a response to mitigate the Farm Bureau's concerns about the lump sum being based on the customer's total bill rather than only the uneconomic portion of the bill.

PG&E's derivation of the lump-sum charge to be applied to customers that miss CTC payments appears to be consistent with this optimal outcome. PG&E states that the proposed lump-sum payment ". . . is neither a 'penalty' nor is it meant to be unnecessarily punitive, but rather is intended to provide a reasonable 'amount certain' for the customer's total CTC responsibility . . . ." (Exhibit 6, p. 6.) Although PG&E also states that the lump sum represents an "upper range" estimate, the approach provides a good starting point for developing an

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[27] Our requirement that each utility provide clear and precise tariffs for all customers will help to ensure that customers understand these obligations.

[28] We also note that if the lump-sum payment were lower than the customer's net present value transition cost obligation , then it would provide an incentive to pursue alternative generation, and take actions to incur the lump-sum penalty. Conversely, if the lump-sum payment were higher than the customer's net present value transition cost obligation, a customer that believes it cannot adequately provide notice of departure or meet CTC payments would, in fact, have a disincentive to pursue alternative generation. However, if the lump-sum payment accurately reflected the customers net present value transition cost obligation, then the lump sum is competitively neutral.

optimal lump-sum amount. Two modifications to PG&E's original lump-sum proposals are necessary for the lump sum to effectively represent a best estimate of the customer's remaining transition cost obligation.

First, the lump sum must account for transition cost amounts already paid by the customer. To make the customer pay the full original lump sum even if that customer had met monthly transition cost obligations as a full service or direct access customer would be a double collection of some of that customer's transition cost obligation. In fact, the lump sum originally proposed by PG&E for customers that failed to pay CTC attempted to account for cumulative payments received. This lump-sum penalty is scaled to the number of months remaining in the transition period. PG&E indicates that the scaling formula is "reasonably representative of the upper range of current estimates for the company's outstanding total unamortized CTC requirements . . . ." (Exhibit 6, p. 14.) Although this is somewhat different from scaling an individual customer's lump-sum penalty to reflect that customer's actual CTC contributions to date, such a customer-specific penalty may be infeasible. PG&E's approach is a reasonable approximation.

In contrast to its proposed penalty for failure to pay CTC, PG&E's original lump-sum proposal for the penalty for failure to provide notice was not scaled to reflect cumulative transition cost collections, but was fixed at two times the customer's reference period bill. As proposed, this penalty could result in a double counting of CTC by failing to reflect a customers' CTC payments made before departure from utility distribution services. ORA raised this point in its testimony, and PG&E agreed in its rebuttal that the lump-sum penalty for failure to provide notice should also be scaled in a fashion identical to the penalty for failure to pay CTC. The most recent versions of the PG&E tariffs reflect these changes.

The most recent version of the Edison tariffs regarding both penalties for failure to provide notice and failure to pay CTC also use a lump-sum penalty calculation that would to some extent reflect that customer's CTC payments made before enforcement of the lump-sum penalty. Edison used a different approach for calculation of the lump-sum payment. In Edison's proposal, if the lump-sum penalty must be assessed on the customer, the lump-sum payment would equal that customer's monthly CTC payment amount multiplied by the number of months remaining in the transition period. This approach seems more straightforward on initial evaluation, because it is based on actual monthly CTC payments. However, under the rate freeze, the customer's monthly CTC payments are not based on any estimate of that customer's CTC obligation, but rather on the residual of the frozen rate less all other charges. Therefore, actual monthly CTC payments might fluctuate greatly, and would certainly have no direct bearing on or reflection of the customer's total transition cost obligation. For this reason, we will order Edison to change its lump-sum penalty calculation to one similar to PG&E's. We also order SDG&E to incorporate these provisions in its tariffs.

Second, the lump-sum amount must be trued-up to reflect changes to the utility transition cost requests that will be addressed in Phase 2 of this proceeding. The utilities' estimates of the customer's full transition cost obligation used to develop the lump-sum payments are obviously based on each utility's request for transition costs in this proceeding. The lump-sum payments should be scaled up or down proportionately to reflect our decisions in these proceedings and the Diablo Canyon proceeding, A.96-03-054, as well as D.96-12-083 regarding Palo Verde Nuclear Generating Station.

We realize that this process involves a certain amount of forecasting. Although this is a prospect we have sought to avoid when possible, it appears the only reasonable means of achieving our goal of making the lump-sum payment reflect departing load customer's total net present value transition cost obligation. We also note that participants to the workshop have implicitly accepted use of these forecasts by agreeing for the most part with the use of a lump-sum payment in penalty mechanisms for departing load. In any case, the number of customers to which these kinds of penalties would apply is small, which means that the magnitude of potential forecast risk will be small in the aggregate.

Therefore, after issuance of the Phase 2 decision, the utilities shall file revised terms and conditions tariffs for departing load that reflect these changes in transition cost forecasts and includes the most recently adopted updates of costs. In the meantime, the utilities and other parties should consider a method that can be used to scale the lump-sum penalty calculation mechanism when the Phase 2 decision is issued. PG&E stated that the estimate behind the lump-sum payment represents an upper range for the customer's transition cost obligation. Among other things, parties might work together to reach agreement on whether the lump-sum payment should be scaled to represent an upper-, mid-, or low-range estimate. Parties may also work to reach agreement on a stipulated long-term price forecast, the use of which would be strictly limited to scaling of the lump-sum payment. This may be an appropriate subject to discuss in workshops to be held later this year. Further guidance will be provided by ruling at a later date.

8.7.4. Final Departing Load Customer Lump-Sum Payment in 2001

Departing load tariffs originally filed by PG&E and Edison required departing load customers to make a final lump-sum CTC payment on March 31, 2002 or at some other time as determined by the Commission. This lump-sum payment would not be pursued as a penalty for failing to provide notice of departure or failure to pay CTC, but instead would be required of all departing load customers. Non-utility parties disagreed with this proposal, stating that the final lump-sum payment could be large and impose a hardship on departing load customers. Workshop participants agreed that it would be reasonable to offer departing load customers the option to make a final lump-sum CTC payment or some form of continuing periodic transition cost payments. Participants agreed that these periodic transition cost payments would not necessarily be an extension of monthly payment arrangements for the duration of the remaining transition cost recovery period, but recommended that the Commission should address the frequency and duration of the payment options at a later date.

We agree that requiring a final lump-sum payment of remaining transition cost obligation could impose significant hardship on departing load customers. This would also place significant forecast risk on customers and shareholders. We approve of the recommended approach to evaluate and establish periodic payment options for departing load transition cost obligations after 2001. These obligations include ongoing costs eligible for continuing recovery and those costs which have been allowed to be deferred including employee-related and restructuring implementation transition costs. To implement this recommendation we will order utilities to file applications no later than January 30, 2001 which propose a method for continuing periodic transition cost payment arrangements for departing load customers. These applications should also provide forecasts of remaining transition cost obligations of departing load customers that would be used as a basis for the final lump-sum payment option and a method to determine the way lump-sum payments would reflect continued periodic CTC payments in the event that a customer should choose to make the lump-sum payment sometime during the proposed periodic payment period.

8.8. Procedural Mechanisms to Update Terms and Conditions Tariffs

We have provided parties augmented procedures for review of interim transition cost tariffs. We intend to continue this practice and asked workshop participants to recommend a procedural means to continue to offer this enhanced opportunity for reviewing future utility proposals to modify transition terms and conditions tariffs. For 1997, participants recommend two means of reviewing proposed tariff changes. First, participants suggested that some review and discussion could take place in the workshops scheduled to address balancing accounts that are planned for the summer. Second, participants suggested that it may be appropriate to expand the standard advice letter filing service list to include those parties with broader restructuring-related interests and doubling the protest period from 20 to 40 days. PG&E recommends that a 30-day protest period for significant update filings, following instructions from assigned ALJs, would strike a reasonable balance between preserving existing advice letter time lines and giving parties the necessary additional time to respond to important restructuring filings. Participants also agreed that parties have the option to request that an advice letter be turned into an application, which would result in an even greater opportunity to scrutinize the tariff proposal. During the transition period (1998-2001), participants agreed that modifications to tariffs could be reviewed in advice letter filings subject to the same extended opportunities for review or in the annual transition cost proceedings.

We agree that additional workshops may be necessary to review proposed CTC terms and conditions tariffs in 1997, particularly because parties have not yet seen these tariffs for full service and direct access customers. Whether workshop activity addressing CTC terms and conditions tariff issues should take place in potential balancing account workshops or in separate workshops is unclear at this time. Additional procedural guidance will be provided by a later ruling.

Once the Phase 2 decision is adopted, utilities will be required to formally file tariffs by advice letter. We will utilize suggestions for an augmented advice letter process. The advice letter should be filed on each utility's standard advice letter service list, the service list for R.94-04-031/I.94-04-032, and the service list for this docket. We adopt PG&E's recommendation for expanding the protest period to 30 days. This procedure has been used previously to allow for protests to utility postings of the monthly QF energy payments. We will evaluate the responses to future advice letter filings to determine whether other tariff changes require additional workshop review.

After 1997, it is reasonable that the utilities use either the annual transition cost proceeding or the advice letter process to make tariff modifications, depending on the timing and the ramifications of such requests. The primary reason for the extended service and protest period for 1997 is to provide for both the busy procedural schedule for all restructuring-related initiatives and new restructuring-related tariffs. We may not need such augmentations to the advice letter process during the entire transition period, but will retain them at least for 1998. We will revisit this issue in the 1998 transition cost proceeding. We also note that parties may use protests to advice letters requesting that tariff modifications be turned into applications. We caution the utilities not to abuse the advice letter process by using them to request authorizations that would more appropriately be sought in an application.

9. Comments on Proposed Decision and Alternate Decision

Timely comments on both the ALJ proposed decision and the alternate proposed decision were filed by PG&E, Edison, SDG&E, ORA, TURN *et al.*, CUE, Farm Bureau, CIU *et al.* and EPUC/CAC. The City and County of San Francisco and the City of San Diego's Metropolitan Wastewater Department also filed comments, along with motions to intervene. Timely reply comments were filed by PG&E, Edison, SDG&E, ORA, TURN *et al*., and the City and County of San Francisco. We have incorporated these comments as appropriate, which were particularly helpful in regards to technical clarification necessary to implement the Commission's findings. We emphasize that in accordance with Rule 77.3, comments which merely reargue positions taken in briefs are accorded no weight. Furthermore, Rule 77.4 provides that comments are not to include new factual information which has not been tested by cross-examination. Such comments will not be relied on as the basis for assertions made in post publication comments.

The comments have addressed several issues, including the following areas: definition of current costs, clarifying the deferral of costs, clarifying the 1999 transition cost proceeding, clarifying exemptions, and addressing the provisions of § 369. We have addressed these issues throughout the decision, as appropriate.

Findings of Fact

1. The requirement that allocation of transition costs shall not result in rate increases beyond June 10, 1996 levels requires that the CTC portion of a customer's bill be computed on a residual basis, i.e., the difference between the total rate and all other charges, including the Power Exchange price.

2. The Joint Recommendation is not a settlement and is accorded appropriate weight.

3. Recovery of generation-related transition costs is not intended to be without risk, but § 330(t) provides the IOUs a reasonable opportunity to fully recover transition costs.

4. Other than employee-related transition costs addressed in § 375, restructuring implementation costs addressed in § 376, and any generation-related transition costs

which are displaced because of the collection of funds addressed in § 381(d), current transition costs must be recovered as incurred.

5. Greater revenues are available for total transition cost recovery when assets with a higher rate of return are accelerated prior to assets with a lower rate of return, and in a manner that maximizes the tax benefit of such amortization.

6. It is in the interests of both ratepayers and shareholders to ensure that the greatest amount of revenues is available to collect transition costs, rather than being applied to interest and carrying costs.

7. Ratepayers benefit from maximizing the amount of revenues to apply to transition cost recovery, because if transition costs are collected as expeditiously as possible, the rate freeze may end before December 31, 2001.

8. Shareholders benefit from ensuring that the greatest amount of revenues is available to collect transition costs, because there is a greater likelihood of full recovery of those costs.

9. It would not be equitable to allow the utilities to have the flexibility to accelerate the recovery of assets that do not bear a rate of return and simultaneously allow the utilities to apply a lower interest rate to their CTC revenue accounts.

10. We have not yet adopted a definition of regulatory assets for purposes of transition cost recovery, although regulatory obligations are included in the definition of generation-related assets provided for in AB 1890.

11. Recovery of regulatory assets is probable because there is no reason to assume that frozen rates will not result in sufficient headroom to fully recover transition costs.

12. Regulatory assets that may be subject to write-off due to FASB Statement No. 71 should be amortized ratably over a 48-month period. The specific regulatory assets to which this finding applies will be determined after Phase 2 eligibility is established.

13. To the extent these assets adhere to the requirements of § 367, generation-related regulatory assets remain recoverable through the CTC, even if written-off for financial accounting purposes.

14. The utilities have the opportunity to accrue revenues to offset transition costs prior to the beginning of the transition period because the rate freeze commenced on January 1, 1997, pursuant to D.96-12-077.

15. The proceeds from rate reduction bonds will have a significant impact on transition cost recovery.

16. An annual transition cost proceeding will help to ensure that we can provide for unanticipated problems.

17. We will not know the extent to which transition costs are uneconomic until market valuation is completed and until we determine the amount of fixed costs that are recovered in the Power Exchange market clearing price.

18. We must ensure that we can track recovery of transition costs on a detailed basis, so that we can determine when those transition costs are fully collected, and we must ensure that adequate review is provided for to ensure that only the uneconomic portion of transition costs is recovered.

19. Current ratemaking principles remain essentially intact, including the accounting principle of matching revenues with expenses; therefore, excepting costs whose recovery may be deferred beyond 2001 as discussed herein, current costs should be recovered first.

20. To the extent that revenues did not cover costs in the current period, revenues should be applied first to transition costs incurred during that period and then to scheduled amortization.

21. As assets which are currently included in rate base are amortized, rate base should be reduced correspondingly, including the impact of associated return and income taxes.

22. Generation-related assets should be written down to the estimated market value, but not below, on an asset-by-asset basis.

23. Similar to balancing accounts established today, the utilities should manage the 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 over-collections of CTC. To the extent that over- and under-collections occur, interest

will accrue at the 90-day commercial paper rate, with the exception of the deferred generation-related transition costs displaced because of funding the programs addressed in § 381(d).

24. To the extent feasible, the transition costs addressed in §§ 375, 376 and 381(d) should be recovered before 2001, similar to current ratemaking practices, but may be deferred to the extent such recovery will put generation-related assets at risk. Section 375 costs may be collected through 2006 and collection of § 376 costs may continue until fully recovered. Any deferrals of these costs may accrue interest at the 90-day commercial paper rate. In addition, to the extent generation-related transition cost recovery is impacted by the collection of renewable program costs under § 381(d) during the rate freeze period, those displaced generation-related transition costs may be collected in the period January 1, 2002—March 31, 2002. Shareholders must bear any associated carrying costs.

25. Establishing memorandum accounts to track transition cost obligations and revenues separately for customers on each side of the fire wall is a useful way to ensure that transition cost obligations are not shifted from one side of the firewall to another.

26. Current application of the EPMC methodology does not allocate costs to the disaggregated level of rate schedule, tariff option, or contract.

27. It is reasonable to require that the utilities track transition cost obligations and payments at the rate group level. Rate groups are the units for which marginal cost revenue responsibility and allocated revenue are determined.

28. The definition of departing load does not apply to Western's customers who are increasing their allocation of federal preference load and PG&E load in a manner contemplated under the existing Contract 2948-A.

29. To the extent that FERC imposes a CTC on the contracts addressed herein, we will develop a process to adequately account for these funds to offset transition cost recovery and to make any necessary adjustments to the firewall memorandum accounts.

30. It is reasonable to adopt the stipulated market clearing price of 2.4 cents per kilowatt hour for the limited purpose of developing an estimate of the total transition cost level applicable for 1998, which may also be important for developing the rate reduction bond applications. Our approval of this stipulated market price does not establish a precedent for any other purpose.

31. CTC tariffs should be constructed to provide the necessary tariff information for utility service customers, direct access customers, and departing load customers.

32. To the extent possible, the billed CTC should be based on metered consumption.

33. It is appropriate that one option for determining the load of departing customers should include reliance upon third-party metering, if a verification of that meter is provided and provided that each party shall bear its own costs for any verification process.

34. It is inappropriate for a utility to require current metered information to determine departing load; rather the customer should be able to select the billing determinant to be applied in consultation with the utility.

35. Customers should be able to change the rate basis used in their CTC calculation by providing current metered information which demonstrates that if they were still taking full utility service, they would be under a different rate schedule.

36. Any transition cost metering option should be available to full service customers, direct access customers, and departing load customers.

37. Providing CTC tariffs for full service, direct access, and departing load customers in one central area of the tariffs will assist the customer in assessing how its CTC calculation and terms may change under various service alternatives.

38. CTC amounts that would otherwise have been paid by exempt customers must be tracked according to the type of exemption and by large and small customer class, as defined by the fire wall requirements delineated in § 330(v).

39. Each utility should provide special procedures which allow departing load customers to cure failures to provide notice of departure and failure to pay CTC.

40. A two-stage approach to establishing a penalty for failure of departing load customers to pay CTC is reasonable.

41. PG&E's derivation of the lump-sum payment reflects a scaling formula that helps to account for transition costs already paid by the customer and should be adopted for PG&E, Edison, and SDG&E.

42. The lump-sum amount must be trued-up to reflect adopted transition cost estimates, as determined in Phase 2 of these proceedings.

43. Requiring departing load customers to pay a final lump-sum payment of the transition cost obligation remaining after March 31, 2002 could impose significant hardship on departing load customers.

44. It is appropriate to require PG&E, Edison, and SDG&E to expand the standard advice letter filing service list to include the service list to R.94-04-031/I.94-04-032 and this proceeding.

Conclusions of Law

1. Transition costs are defined in §§ 367, 368, 375, and 376. For generation-related assets, transition costs are those that prove to be uneconomic in the new competitive framework.

2. For the most part, generation-related transition costs must be recovered by December 31, 2001. AB 1890 states that transition costs must be recovered as expeditiously as possible.

3. Transition costs related to power purchase agreements and QF contracts may be collected for the duration of the contract.

4. Employee-related transition costs may be collected through December 31, 2006.

5. The collection of transition costs may extend though March 31, 2002 to the extent collection of transition costs is impacted by CTC exemptions, the costs of funding renewables programs as defined in § 381(d), or BRPU settlement costs, with certain additional provisions, as defined in § 367.

6. Commission-approved electric restructuring implementation costs that are not collected from another source and which reduce the ability of the utilities to collect

generation-related transition costs may be continue to be collected after December 31, 2001, as provided by § 376.

7. Pursuant to § 367, this Commission must make the final determinations of the uneconomic costs associated with generation-related assets. In addition, in order to determine the transition costs for generation-related assets, we must net the negative (above-market costs) and positive (below-market costs) transition costs of all utility-owned generation related assets. Valuation of these assets must occur by year-end 2001.

8. The utilities must amortize their uneconomic costs such that their recorded rate of return does not exceed the authorized rate of return on ratebase.

9. The utilities are at risk for generation-related transition costs that are not recovered by December 31, 2001.

10. We must implement the newly-added Public Utility Code sections according to the plain meaning of the statute, applying our knowledge of ratemaking practices, common sense, and our duty in carrying out the public interest.

11. Pursuant to D.96-12-077, as of January 1, 1997, rates are frozen at levels that were in place on June 10, 1996. This has the effect of allowing the utilities to accrue revenue prior to the beginning of the mandated transition period.

12. PG&E's Rate Restructuring Settlement discussed the acceleration of the recovery of generation-related regulatory assets, but this must be evaluated in the context of the statute as a whole.

13. The utilities should accelerate the collection of those transition costs which earn a high rate of return and in a manner which provides the greatest tax benefits. At a minimum, the utilities should accelerate depreciation of these assets on a straight-line basis over a 48-month amortization period, including associated taxes and the reduced rate of return.

14. Regulatory assets which are subject to write-off because of FASB Statement No. 71 should be amortized ratably over a 48-month period. The specific assets to which this requirement applies will be determined after Phase 2 eligibility is determined.

15. In order to accommodate ongoing market valuations and accelerated recovery, PG&E, Edison, and SDG&E should recalibrate the remaining months of the recovery schedule to adjust the amortization schedule through the end of the transition period.

16. It is reasonable to require monthly and annual reports to track the recovery of transition costs, as well as to institute an annual transition cost proceeding, separate from the Revenue Adjustment Proceeding.

17. Employee-related transition costs have been protected by statute.

18. Pursuant to § 369, CTC does not apply to service taken under tariffs, contracts, or rate schedules that are on file, accepted, or approved by the FERC, unless otherwise authorized by the FERC.

19. While transition cost responsibility should be subject to as few exemptions as possible, the definition of departing load does not apply to Western's customers who are increasing their allocation of federal preference load in a manner contemplated under the existing contract, as described herein. A customer outside of these specific federal preference power contractual agreements, or similar arrangements subject to § 369, who was taking PG&E service subject to CPUC jurisdiction prior to December 20, 1995, and then displaced that PG&E service with third-party generation, which is wheeled to that customer under a FERC-jurisdictional tariff, will be subject to CTC.

20. It is reasonable at this time to consider metering reliability according to the standards designated for utility meters in tariff Rule 17 for PG&E and Edison and Rule 18 for SDG&E.

21. Tariffs should be designed so that customers can understand the costs and implications of choosing various available service options.

22. As decisions are forthcoming in the direct access and unbundling proceedings, CTC tariffs may require modifications.

23. It is reasonable to accept the tariff modifications stipulated to at the Energy Division workshops.

24. The fire wall established by § 330(v) is established to address revenue shortfalls due to exemptions and to protect ratepayers from transition cost obligations being shifted as a result of these revenue shortfalls.

25. The memorandum accounts and methodology that have been proposed by PG&E and Edison in Exhibits 7 and 10, respectively, are acceptable for tracking these exemptions and should be implemented by PG&E, Edison, and SDG&E.

26. Section 374(a)(4) states that the provisions of subdivision (a) are no longer operative after March 31, 2002; therefore, irrigation district customers are no longer exempt from any transition costs which accrue in the period after March 31, 2002.

27. It is reasonable to adopt the same procedures for PG&E, Edison, and SDG&E for resolving dispute resolutions in departing load CTC statements that we found reasonable for PG&E in D.96-11-041.

28. It is reasonable to develop unique penalty procedures to ensure that departing load customers cannot bypass transition costs and increase the transition cost burden on full service and direct access customers.

29. PG&E, Edison, and SDG&E should treat CTC deposits according to Rule 7 of their existing tariffs; therefore, each utility is prohibited from applying a customer's deposit toward missed CTC payments. Except to the extent that each utility's Rule 7 allows the application of deposits to closing bills, CTC deposits may be applied to outstanding departing load transition costs at the end of the transition period.

30. The lump-sum payment used as a last-resort penalty for departing load customers is not anticompetitive.

31. It is reasonable to offer departing load customers the choice of making final lump-sum CTC payments to reflect the transition costs ensuing after March 31, 2002 or to allow these customers some form of continuing transition cost payments.

32. It is reasonable to augment the advice letter process for modifications to transition cost tariffs that occur in 1997 and 1998.

33. A 30-day protest period for transition cost advice letters is reasonable, in light of the many activities occurring in electric restructuring in 1997 and early 1998, and the complexity of the issues addressed.

34. This order should be effective today so that the ratemaking mechanism and tariff procedures may be implemented expeditiously.

INTERIM 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 establish preliminary Transition Cost Balancing Accounts in compliance with the general guidelines established in this decision. These pro forma tariffs shall be filed and served in this proceeding by June 27, 1997. Final tariffs shall be filed after the Phase 2 decision.

2. The Energy Division shall convene workshops to address detailed issues of applying the guidelines adopted in this decision and to address specific issues that may arise in implementation of these tariffs. Interested parties shall serve comments on tariff issues raised in the utilities' filings by July 8, 1997. Preliminary workshops shall be held on July 14, 15, and 16, 1997. These workshops may also be used to address terms and conditions tariff issues, as described in this decision. The Energy Division shall file and serve its workshop report on or before August 22, 1997 and parties will be afforded an opportunity to file and serve comments on the workshop report. The Energy Division shall convene additional tariff workshops in the fall after issuance of the Phase 2 decision if necessary. Further guidance shall be provided by ruling.

3. PG&E, Edison, and SDG&E shall file applications no later than June 1, 1998 to request recovery of transition costs in 1999. Annual transition cost proceedings shall be used to establish the reasonableness of PG&E, Edison, and SDG&E in accelerating recovery of transition costs and in estimating the market value of their assets subject to market valuation.

4. The Energy Division shall convene workshops no later than 45 days following the filing of the applications for 1999 transition cost recovery to address the implementation of these proceedings, including how to streamline such proceedings.

5. PG&E shall modify its departing load tariff to clarify that no competition transition charge will be applied to changes in allocation to load taken under Western Administration Power Association Contract 2948-A.

6. A market rate forecast of 2.4 cents per kilowatt hour shall be used to estimate transition costs for 1998.

7. By July 1, 1997, PG&E, Edison, and SDG&E shall file and serve pro forma tariffs which provide general information on transition costs and the calculation of competition transition charge, as well as specific language delineating particular requirements and terms and conditions for utility service customers, direct access customers, and departing load. Implementation issues may be discussed at the workshops ordered in Paragraph 4.

8. PG&E, Edison, and SDG&E shall follow augmented advice letter procedures, including expanded service and a 30-day protest period, as described in this decision, for filing CTC tariffs and proposing to modifying such tariffs.

9. Final CTC tariffs shall be filed by augmented advice letter filing, as described in this decision, after the Phase 2 decision is issued. Further guidance shall be forthcoming in that decision.

10. PG&E, Edison, and SDG&E shall file applications, as described in this decision, by January 30, 2001 which address the lump-sum payment and periodic payment options for departing load customers.

This order is effective today.

Dated June 11, 1997, at San Francisco, California.

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

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