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Decision 97-11-074 November 19, 1997

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

(See Appendix A for appearances)

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INTERIM OPINION: TRANSITION COST ELIGIBILITY

1. Summary

In this decision, we determine the eligibility of various categories of non-nuclear costs for transition cost recovery , consistent with the mandates of Assembly Bill (AB) 1890 and the Preferred Policy Decision (Decision (D.) 95-12-063, as modified by D.96-01-009). We establish the non-nuclear cost categories eligible for transition cost recovery and also quantify the net book value of various generation assets currently owned by Pacific Gas and Electric Company (PG&E), Southern California Edison Company (Edison), and San Diego Gas & Electric Company (SDG&E).[1] This net book value calculation is the appropriate starting point for market valuation, which results in a final determination of transition cost recovery for those assets subject to market valuation.

In the Preferred Policy Decision, we defined transition costs as the net above-market costs associated with uneconomic generation assets. Uneconomic assets are those assets whose net book value exceeds their market value. We established that each utility's net above-market costs would be determined after offsetting the benefits associated with economic assets against the excess costs of uneconomic assets. (Preferred Policy Decision, mimeo. at 116.) Eligible costs that do not undergo market valuation are compared to the Power Exchange market clearing price on an ongoing basis in order to determine the uneconomic portion. AB 1890 (Stats. 1996, Ch. 854,) affirmed our approach to transition cost recovery and added §§ 367 - 377 to the Public Utilities (PU) Code.[2] Much of the work in this phase, Phase 2, of this proceeding,

[1] The Phase 1 transition cost issues were addressed in Decision (D.) 97-06-060, which established a transition cost balancing account for each utility and addressed various ratemaking issues related to the order in which revenues are applied to offset various transition costs. Transition costs for PacifiCorp are addressed in Application (A.) 97-05-011, for Sierra Pacific Power Company in A.97-06-046, for Kirkwood Gas & Electric Company in A.97-07-005, and for Southern California Water Company in A.97-08-064.

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

consists of establishing the baseline against which market valuation will later be measured and determining which eligible cost categories will be recovered on an actual, recorded basis, and which costs should be captured through the market valuation process. Many of the most contentious issues center on whether certain costs are "sunk" costs and therefore eligible for transition cost treatment, or whether such costs are "going forward" costs that should be recoverable from the new competitive generation market.

Work on Phase 2 began with an independent audit of the figures presented in the utilities' transition cost filings. The audit was performed by Mitchell Titus, LLP, with additional work by the Barrington-Wellesley Group, and was managed by the Commission's Energy Division. The purpose of the audit was to evaluate each utility's estimates of net book value and calculations of transition costs that have yet to be incurred. The independent audit was requested by several parties and ordered by Assigned Commissioner Ruling (ACR) dated August 1, 1997. That ruling recognized that while the audit is unlikely to resolve all of parties' concerns, it would prove a useful starting point for testimony on these issues, and would likely streamline the hearings considerably.

The utilities have presented the following amounts as non-nuclear costs eligible for transition cost recovery as of January 1, 1998. These figures do not include any assessment of the actual uneconomic value of such assets:

PG&E:	$35,413.351 million
Edison:	34,255.878 million
SDG&E:	3,483.777 million
Total:	$73,153.006 million

We emphasize that these are estimates of total costs proposed to be eligible for transition cost recovery.[3] In most cases, we do not forecast total transition cost recovery,

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[3] On a net present value basis, the utilities estimated the following amounts in transition costs, including nuclear assets:

Footnote continued on next page

which will ultimately be determined by the market valuation process, the Power Exchange price, and the limitations of the rate freeze, as discussed more fully below. Attachments 1 and 2 delineate the utilities' estimates of the magnitude of the uneconomic costs involved. Again, we emphasize that we are not approving such forecasts, but are providing these amounts for informational purposes. Only actual uneconomic transition costs will be recovered.

We do not address capital additions, which are being reviewed in a separate proceeding, nor do we address employee-related transition costs or restructuring implementation costs at this time. PG&E, Edison, and SDG&E shall establish subaccounts as placeholders in their transition cost balancing accounts to track recorded employee-related costs and any generation-related transition costs displaced due to recovery of restructuring implementation costs as defined in § 376. Actual employee transition costs will be reviewed in future annual transition cost proceedings. Restructuring implementation costs will be addressed in a separate proceeding, as will the market valuation procedures for retained assets.[4]

At the outset, it is important to note that the majority of costs eligible for transition cost recovery are prescribed by law. Costs related to nuclear generating assets and above-market contracts with Qualifying Facilities (QFs) account for the majority of estimated transition costs. Other than those costs related to on-going contractual obligations, most of the non-nuclear generation-related costs eligible for transition cost recovery are plant-related, which were verified by the transition cost audit. The majority of these costs are not challenged by any party.

PG&E - $11,300 million; Edison - $13,837 million; and SDG&E - $1,938 million, for a total of $27,075 million.

[4] Throughout these proceedings, we have anticipated additional phases to consider market valuation for retained assets and restructuring implementation costs. On January 1, 1998, the provisions of Senate Bill (SB) 960 becomes effective. Among other things, SB 960 establishes specific deadlines for handling proceedings. It is more efficient, therefore, to require PG&E, Edison, and SDG&E to file separate applications for each of these issues.

2. Background and Procedural History[5]

As defined in the Preferred Policy Decision, transition costs arise from generation assets, nuclear power plant settlements, power purchase agreements, QF contracts, and the reasonable costs of early retirement or retraining programs for employees. We defined uneconomic costs for generation assets as those occurring when the market value at the time of divestiture, spinoff, 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 invester-owned utilities (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. As directed by the Preferred Policy Decision and various rulings, Application (A.) 96-08-001, A.96-08-006, and A.96-08-007 were filed on August 1, 1996 by PG&E, Edison, and SDG&E, respectively. On August 30, PG&E, Edison, and SDG&E filed A.96-08-070, A.96-08-071, and A.96-08-072, respectively. These applications were consolidated by ruling.

On September 23, 1996, 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. On October 21, the utilities amended A.96-08-070, A.96-08-071, and A.96-08-072 to reflect the impact of and revisions required by AB 1890, specifically the requirements of newly added §§ 367, 368, 369, 372, 373, 374, 375, and 376.

A prehearing conference (PHC) in Phase 2 was held on January 21, 1997. The assigned Commissioners issued a ruling on February 4, which clarified the scope of

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[5] See D.97-06-060 for a more complete procedural history.

Phase 2 and established the procedural schedule.[6] The independent audit report was filed and served on March 21, 1997. PG&E, Edison, and SDG&E filed their responses to the audit report on April 10. Phase 2 testimony was served by the Office of Ratepayer Advocates (ORA), jointly by The Utility Reform Network (TURN) and the Utility Consumer Action Network (UCAN) (collectively, TURN), jointly by California Industrial Users (CIU), California Large Energy Consumers Association (CLECA), and California Manufacturers Association (CMA) (collectively, CIU), by the Federal Executive Agencies (FEA), jointly by the Energy Producers and Users Coalition (EPUC) and the California Association of Cogenerators (CAC) (collectively, EPUC), and jointly by Independent Energy Producers (IEP) and the California Cogeneration Coalition (CCC) (jointly, IEP). Rebuttal testimony was served on May 9. An additional PHC was held on May 15 and evidentiary hearings were held from May 19 through June 19. A Joint Comparison Exhibit (Exhibit 121) was filed on June 30. Concurrent opening briefs were filed by PG&E, Edison, SDG&E, ORA, TURN, CIU, FEA, the California Farm Bureau Federation (Farm Bureau), EPUC, and IEP on July 21. Reply briefs were timely filed by PG&E, Edison, SDG&E, ORA, TURN, CIU, FEA, EPUC, and Enron on August 1.

On July 16, 1997, we issued D.97-07-059 which directed PG&E, Edison, and SDG&E to establish memorandum accounts to track the differential between the authorized rate of return and the reduced transition cost rate of return, pending a finding on when the reduced transition cost rate of return should be applied. Pursuant to that decision, the administrative law judge (ALJ) directed interested parties to file and serve supplemental briefs on this issue by August 8. Reply briefs were filed and served on August 18.

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[6] In that ruling, the assigned Commissioners established that incremental capital additions made after December 20, 1995 would be considered in a separate proceeding. Accordingly, issues related to capital additions are not addressed in this decision.

In addition to the Phase 2 testimony and filings, we address certain policy issues raised in the Phase 1A briefs and reply briefs.[7] Briefs were filed on November 8, 1996 by PG&E, Edison, SDG&E, ORA, TURN (jointly with UCAN and the California Department of General Services), CIU, EPUC, the Farm Bureau, CLECA and CMA (jointly), and the California Energy Commission (CEC).[8] Reply briefs were filed on November 15 by PG&E, Edison, SDG&E, ORA, TURN, CIU, EPUC, CalEnergy Company, and the Coalition of California Utility Employees. Finally, we address comments by PG&E, Edison, and SDG&E as to factual eligibility issues, which were filed on February 14, 1997 in response to a joint Assigned Commissioners' and ALJ ruling issued on January 17. Responses to these comments were filed by ORA, TURN, and jointly by CIU, CLECA, CMA, EPUC, and CAC on February 28. The utilities filed reply comments to these responses on March 10, 1997.

3. AB 1890 and Transition Costs

As we discussed in D.97-06-060, AB 1890 adds several new sections to the PU Code, and endorses, for the most part, this Commission's approach to transition costs.[9] With certain exceptions, the legislation provides for a nonbypassable charge, the competition transition charge or 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 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

[7] Phase 1A established a briefing schedule to identify threshold policy issues that must be considered.

[8] EPUC filed a motion for leave to late-file its Phase 1A brief, which was filed on November 12. That motion is granted.

[9] Some of the sections added to the PU Code by AB 1890 have been subsequently amended by SB 477 (Stats. 1997, Ch. 275).

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 (i.e., generation assets, nuclear power settlements, power purchase contracts, and regulatory obligations), § 367 provides for transition cost recovery of costs associated with Biennial Resource Planning Update (BRPU) settlements, capital additions for units existing as of December 20, 1995 and which we find reasonable to maintain facilities until 2002, Edison's fixed fuel and fuel transportation contracts, and an expanded definition of employee-related transition costs. Section 367 also specifies the period during which particular transition costs may be recovered. Costs of generation-related assets and obligations must be collected by December 31, 2001, with the exception of certain nuclear settlements. 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 programs promoting renewable energy sources, or BRPU settlement costs, with certain additional provisions. Finally, § 376 provides that, to the extent that Federal Energy Regulatory Commission (FERC) or Commission-approved recovery of the costs of utility-funded programs to accommodate implementation of direct access, the Power Exchange, and the ISO reduces the ability of the utilities to collect generation-related transition costs, those generation-related costs may be collected after December 31, 2001, in an amount equal to the implementation costs that are not recovered from the Power Exchange or ISO.

Most importantly, in order to determine the transition costs for generation-related assets, we must net the above-market and below-market transition costs of all utility-owned generation-related assets. Valuation of these assets must occur by year-end 2001.[10] 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.

Section 330 expresses the Legislature's findings and declarations regarding electric restructuring. Section 330 has been included in order to provide guidance in carrying out the statutory provisions of restructuring. We quote relevant subdivisions below:

> "(d) The commission has found, after an extensive public review process, that the interests of ratepayers and the state as a whole will be best served by moving from the regulatory framework existing on January 1, 1997, in which retail electricity service is provided principally by electrical corporations subject to an obligation to provide ultimate consumers in exclusive service territories with reliable electric service at regulated rates, to a framework under which competition would be allowed in the supply of electric power and customers would be allowed to have the right to choose their supplier of electric power.
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> "(e) Competition in the electric generation market will encourage innovation, efficiency, and better service from all market participants, and will permit the reduction of costly regulatory oversight."
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> "(2) Generation of electricity should be open to competition and utility generation should be transitioned from regulated status to unregulated status though means of commission-approved market valuation mechanisms.
>
> "(3) There is a need to ensure that no participant in these new market institutions has the ability to exercise significant market power so that operation of the new market institutions would be distorted.

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

"(n) Opportunities to acquire electric power in the competitive market must be available to California consumers as soon as practicable, but no later than January 1, 1998, so that all customers can share in the benefits of competition."

* * *

"(p) Consistent with federal and state policies, California electrical corporations invested in power plants and entered into contractual obligations in order to provide reliable electrical service on a nondiscriminatory basis to all consumers within their service territories who requested service.

"(q) The cost of these investments and contractual obligations are [sic] currently being recovered in electricity rates charged by electrical corporations to their consumers."

* * *

"(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, 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."

In order to lay the framework for our findings in this decision, we quote extensively from § 367, as amended by SB 477:

"The commission shall identify and determine those costs and categories of costs for generation-related assets and obligations, consisting of generation facilities, generation-related regulatory assets, nuclear settlements, and power purchase contracts, including, but not limited to, restructurings, renegotiations or terminations thereof approved by the commission, that were being collected in commission-approved rates on December 20, 1995, and that may become uneconomic as a result of a competitive generation market, in that these costs may not be recoverable in market prices in a competitive market, and appropriate costs 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 these additions are necessary to maintain the facilities through December 31, 2001. These uneconomic costs shall be recovered from all customers on a nonbypassable basis and shall:

"(a) Be amortized over a reasonable time period, including collection on an accelerated basis, consistent with not increasing rates for any rate schedule, contract, or tariff option above the levels in effect on June 10, 1996; provided that, the recovery shall not extend beyond December 31, 2001,...[with stated exceptions]

"(b) Be based on a calculation mechanism that nets the negative value of all above market utility-owned generation-related assets against the positive value of all below market utility-owned generation related assets. For those assets subject to valuation, the valuations used for the calculation of the uneconomic portion of the net book value shall be determined not later than December 31, 2001, and shall be based on appraisal, sale, or other divestiture. The commission's determination of the costs eligible for recovery and of the valuation of those assets at the time the assets are exposed to market risk or retired, in a proceeding under Section 455.5, 851, or otherwise, shall be final, and notwithstanding Section 1708 or any other provision of law, may not be rescinded, altered, or amended.

"(c) Be limited in the case of utility-owned fossil generation to the uneconomic portion of the net book value of the fossil capital investment existing as of January 1, 1998, and appropriate costs 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 these additions are necessary to maintain the facilities through December 31, 2001. All 'going forward costs' of fossil plant operation, including operation and maintenance, administrative and general, fuel and fuel transportation costs, shall be recovered solely from the independent Power Exchange Revenues or from contracts with the Independent System Operator, provided that for the purposes of this chapter, the following costs may be recoverable pursuant to this section:

"(1) Commission-approved operating costs for particular utility-owned fossil powerplants or units, at particular times when reactive power/voltage support is not yet procurable at market-based rates in locations where it is deemed needed for the reactive power/voltage support by the Independent System Operator, provided that the units are otherwise authorized to recover market-based rates and provided further that for an electrical corporation that is also a gas corporation and that serves at least four million customers as of December 20, 1995, the commission shall allow the electrical corporation to retain any earnings from operations of the reactive power/voltage support plants or units and shall not require the utility to apply any portions to offset recovery of transition costs. Cost recovery under the cost recovery mechanism shall end on December 31, 2001.

"(2) An electrical corporation that, as of December 20, 1995, served at least four million customers, and that was also a gas corporation that served less than four thousand customers, may recover, pursuant to this section, 100 percent of the uneconomic portion of the fixed costs paid under fuel and fuel transportation contracts that were executed prior to December 20, 1995, and were subsequently determined to be reasonable by the commission, or 100 percent of the buy-down or buy-out costs associated with the contracts to the extent the costs are determined to be reasonable by the commission.

"(d) Be adjusted throughout the period through March 31, 2002, to track accrual and recovery of costs provided for in this subdivision. Recovery of costs prior to December 31, 2001, shall include a return as provided for in Decision 95-12-063, as modified by Decision 96-01-009, together with associated taxes."

In building this framework, it is also useful to consider the Preferred Policy Decision. AB 1890 reflects several fundamental concepts articulated in the Preferred Policy Decision, in particular the concepts of netting economic and uneconomic costs, and minimization of transition costs:

"This netting of excess costs and benefits fairly reduces the overall level of the utility's transition costs. This netting of economic and uneconmic assets is also a partial way of compensating ratepayers for the loss of continued dedication to public use of economic assets.

"Offsetting uneconomic assets with economic assets is fair in another sense. . .The rate for electricity is thus an average reflecting the costs of both low-cost (economic) and high-cost (uneconomic) assets. It would obviously be unfair if, as part of our restructuring, we were to require customers to pick up the costs of high-cost generation without at the same time accounting for the benefits of low-cost generation. " (Preferred Policy Decision, mimeo. at 118, 119.)

Section 367(d) specifically refers to the rate of return adopted in the Preferred Policy Decision. In discussing the principles underlying that reduced rate of return, we determined that ratepayers should benefit from transition cost recovery and that shareholders should recover lower revenues as transition costs than they would under traditional regulation. In particular, we determined that

> the assurance of full recovery gives the utility no incentive to minimize transition costs. This is counter to our goal of keeping transition costs as low as possible, but it has even worse implications. If the utility is indifferent to the level of transition costs, it would in turn have an incentive to bid low in offering its generation assets' output to buyers in the Power Exchange, with the forseeable effects of depressing the market-clearing price, squeezing the profit margins of competitors, and further increasing transition costs.

4. Need for Forecast of Transition Cost Amounts

PU Code § 370 provides:

> The commission shall require, as a prerequisite for any consumer in California to engage in direct transactions permitted in Section 365, that beginning with the commencement of these direct transactions, the consumer shall have an obligation to pay the costs provided in Sections 367, 368, 375, and 376, and subject to the conditions in Sections 371 to 374, inclusive, directly to the electrical corporation providing electricity service in the area in which the consumer is located. This obligation shall be set forth in the applicable rate schedule, contract, or tariff option under which the customer is receiving service from the electrical corporation. To the extent the consumer does not use the electrical corporation's facilities for direct transaction, the obligation to pay shall be confirmed in writing, and the customer shall be advised by any electricity marketer engaged in the transaction of the requirement that the customer execute a confirmation. The requirement for marketers to inform customers of the written requirement shall cease on January 1, 2002.

At the request of the ALJ, parties briefed the impact of this section on the need for forecasts of the transition cost obligation. Parties agree that, in general, there is no need for a forecast of either the total amount of transition costs or a particular customer's obligation. As discussed in D.96-12-077, D.96-06-060, and D.97-08-056, the rate freeze has created the concept of headroom, which results in the actual rate (the CTC) being computed residually. Because this rate is determined on a residual basis, there is no need to adopt specified transition cost forecasts or rate levels, as was originally conceived in the Preferred Policy Decision. In general, then, the actual transition cost amount will be determined from recorded levels, rather than forecast levels. On January 1, 1998, the recorded transition costs found eligible for transition cost recovery by this Commission will be debited, as appropriate, into each utility's transition cost balancing account. Revenues accruing from the CTC, the market, and the rate reduction bonds will also be tracked. As market valuation occurs for generation assets, corresponding credits will be booked into the transition cost balancing account. Thus, the need for forecasts, always a contentious process, is avoided.

The notice requirement of § 370 does not require a specific forecast of transition costs, but rather the notification that such charges will be made. As the Farm Bureau explains, § 370 should be read in conjunction with other components of the cost recovery plan set forth in § 368. Because § 368(b) requires that individual cost components be separately identified, the CTC must be residually established. Such a residual calculation, together with the rate freeze at June 10, 1996 levels, therefore precludes specifying particular amounts. If transition cost amounts are forecast and then allocated to each rate schedule, contract, and tariff option, the sum of CTC and other rate components, each of which would be allocated independently, based on different allocation methodologies, may be above or below the frozen rate levels. In addition, § 367(e)(1) requires that transition costs be allocated among customer classes, rate schedules, contract rates, and tariff options in substantially the same proportion as similar costs are recovered as of June 10, 1996. We concur that the necessity for forecasts of transition cost amounts is eliminated by the rate freeze and the residual calculation of the CTC. We will require that each utility implement clear, straightforward language in its tariffs, which notifies the direct access customer of the obligation to pay transition costs, consistent with our directives in D.97-06-060.[11]

5. Transition Cost Eligibility and Policy Issues

Generally, the utilities assert that all costs identified in their applications are recoverable as a matter of law under AB 1890. Several intervenors maintain that the Preferred Policy Decision specifically identified the concept of competitive neutrality regarding transition cost recovery and assert that costs which must be recovered by competitors in the marketplace should not be afforded transition cost recovery.

PG&E maintains that because every category of costs in its applications is either included in rates today or explicitly provided for in AB 1890, the Commission must determine that these costs are eligible for recovery as transition costs as a matter of law. Moreover, PG&E contends that it is not required to prove the facts associated with its claims for recovery to recover these costs, but that other parties must disprove these facts in order to advance their fact-based arguments against recovery of certain categories of costs. PG&E believes that if a cost is a generation-related cost or obligation and the cost is not an operating cost of a non-must-run fossil plant, the costs must be deemed eligible for transition cost recovery. PG&E contends that we do not have the authority under AB 1890 to declare that certain costs or cost categories are ineligible for transition cost recovery, because all such costs satisfy the test of eligibility described above.

PG&E believes that the concept of competitive neutrality should not enter into the determination of transition cost eligibility. PG&E states that transition cost recovery is allowed because the utilities are now required to adjust to a new regulatory

[11] D.97-06-060 described two limited exceptions to the need for forecasts of transition cost amounts for departing load customers in order to calculate penalties for failure to pay CTC or failure to provide notice of departure from the system. Forecasts of customer transition cost obligations for these limited purposes will be determined in a later decision. Second, after 2001, transition cost obligations will decline significantly. D.97-06-060 recognizes that some customers may wish to resolve further CTC payments at that time.

framework, unanticipated when resource investment decisions were contemplated and because, until market valuation, the utilities are required to sell their plant output to the Power Exchange and are subject to administratively determined rates of return.

Furthermore, PG&E declares that many of the competitors expected to participate in the new market have various advantages and ways of recovering generation-related costs other than through Power Exchange revenues. For example, QFs recover costs pursuant to long-term contracts and thus will not have to recover all of their "going forward costs" from the Power Exchange. In-state municipal utilities have certain tax advantages and franchises under which they recover a large part of their costs. Out-of-state generators also have franchise customers from which large portions of costs are recovered. PG&E expects that these generators will not attempt to recover all of their sunk costs from the California market.

Edison agrees that the policy guidelines established by the Legislature and this Commission must be adhered to without further requirements being imposed. Edison argues that transition cost recovery was established to allow for recovery of costs associated with investments in plants and contractual obligations incurred in order to provide reliable, nondiscriminatory service. Edison explains that the term "competitive neutrality" has been used out of context and is used in the Preferred Policy Decision to explain only how the collection of CTC will be applied among customers, but does not refer to the various intervenor proposals that transition cost eligibility must exclude any costs that any of a utility's competitors must recover from the market.

SDG&E, too, agrees that the only relevant standards of eligibility are those expressed in AB 1890, which are consistent with the Preferred Policy Decision, and states that the cost categories that are the focus of other parties' concerns are all costs that are reflected in Commission-approved rates as of December 20, 1995. SDG&E contends that costs that may not have been recovered in rates are specifically provided for under either AB 1890 or the Preferred Policy Decision; e.g. employee-related transition costs, restructuring implementation costs, and BRPU buy-out costs. Thus, SDG&E contends there are no factual issues associated with eligibility, only with reasonableness and quantification.

As a matter of policy, the intervenors dispute the utilities' interpretation of eligibility. ORA strongly recommends that our policies be based on the idea that competition begins on January 1, 1998, rather than at the end of the transition period. ORA explains that the primary goals of its policy regarding restructuring are to ensure that the new electric markets work properly and that market forces operate to discipline and minimize the utilities' expenditures for transition costs. ORA therefore recommends that cost recovery for must-run plants should come from the must-run agreements with the ISO and any relevant Power Exchange revenues, rather than from transition cost recovery, and that the "going forward costs" of non-must-run plants must be recovered from competition in the market.

ORA asserts that determination of eligibility is not guaranteed, but is a multi-step process. ORA recommends that we consider the following threshold questions:

1. Is the cost category identified as eligible for transition cost recovery?
2. If eligible, are the costs in this category uneconomic?
3. Should these costs be classified as going forward costs for which recovery must come only through market revenues?
4. If a cost category is eligible and uneconomic, should recovery of this cost be accelerated?
5. What return should be authorized on the unamortized portion of the cost?
6. Does a specific cost item (as opposed to a cost category) meet the criteria required by AB 1890 or by the Commission?
7. Would inclusion of a category of classes exacerbate horizontal or vertical market power issues?

ORA agrees that several cost categories are clearly eligible for recovery as transtion costs. These include ongoing QF contract costs, sunk nuclear costs and incremental cost incentive pricing (ICIP) costs, transaction costs of divesting power plants, and transmission assets deemed generation plant (i.e., step-up transformers and generation radial tie-lines) by the Federal Energy Regulatory Commission (FERC).

TURN asserts that there are important policy issues that must be determined by this Commission, despite the guidance provided by AB 1890. TURN contends that the broad introductory language of § 367 must be interpreted consistent with the specific limitations provided in later portions of that section, particularly the prohibition in

§ 367(c) against recovering "going forward costs" from other than market revenues. Secondly, TURN recommends that the Commission consider the issue of economic or uneconomic assets on an overall basis; that is, if a generation facility is likely to be economic on an overall basis, specific costs associated with that plant should not be eligible for treatment as transition costs.

FEA recommends that several guidelines be adopted to determine eligibility criteria, including that the costs eligible for transition cost recovery must be prudent, that the basic purpose of such recovery is to mitigate the utilities' potential losses, that sunk transition costs must be supported by Commission decisions, that the utilities must mitigate their stranded costs wherever possible, and that competitive neutrality should be an important consideration.

CIU recommends structuring our policy regarding transition cost recovery to ensure that recovery is closely examined according to the underlying principle of competitive neutrality. CIU further explains that the limitations placed on transition cost recovery may lead to several costs claimed by the utilities that will not be recovered either in transition costs or in distribution rates, and that this outcome is consistent with the mandates of the law.

EPUC advocates that § 367 must be interpreted strictly and that the broad recovery alluded to in the first subdivision of § 367 is then limited by additional provisions regarding transition cost recovery, particularly in terms of fossil generation and net book value, as discussed more fully below. EPUC agrees with PG&E that where the Rate Restructuring Settlement (referred to in § 368(h)) conflicts with AB 1890, AB 1890 controls, but argues that the Rate Restructuring Settlement can provide guidance if there is ambiguity over what was intended by the statutory language.

Enron believes that the provisions of AB 1890 are intended to reflect a balance between the competing interests of ratepayers and shareholders and agrees that the central policy issue in Phase 2 is how the limitations expressed in AB 1890 will be applied to restrict the utilities' recovery of transition costs. Enron agrees with CIU that the concept of competitive neutrality is central to the principles delineated in the Preferred Policy Decision regarding transition cost recovery.

5.1. Discussion

We are mindful of the role of these proceedings: the Preferred Policy Decision has been issued; AB 1890 has been signed into law. The purpose of these proceedings is to implement the mandates of the various code sections, and where applicable, the requirements of the Preferred Policy Decision. We fully agree with Edison that this decision must execute Legislature's intent as expressed throughout the many PU Code sections added by AB 1890. However, we strongly disagree with the general assumption, as expressed by SDG&E that:

> In both the Preferred Policy Decision and AB 1890, the Commission and the Legislature expressed their unequivocal intent that it is both appropriate and necessary that utilities should recover all of their uneconomic costs associated with the transition to a competitive market. (SDG&E opening brief, p. 4)

In actuality, the utilities are merely allowed the *opportunity* to recover such costs, which are identified and determined by this Commission. The Legislature did not intend that we abrogate our authority in making such determinations. While we acknowledge the underlying principle that utilities should be allowed a fair opportunity to fully recover the uneconomic costs associated with generation-related assets and obligations, we must also recognize the Legislature's stated goals of implementing competition in the generation market and thereby allowing customer choice.

Our policy determinations are based on the tenets of the law and our preference for moving towards a competitive market as quickly as possible. As a general matter of public policy, we will balance the interests of both ratepayers and shareholders, while at the same time ensuring the viability of the nascent competitive marketplace. Our goal is to provide the utilities with a fair opportunity for full recovery of transition costs and to ensure that recovery of "going forward costs" is appropriately limited, consistent with the law. In this way, we will provide the utilities a fair opportunity to recover uneconomic costs, as required by law and policy, without impacting the competitive market and thereby insuring that recovery of transition costs, to the extent possible, will not decrease the competitive options available to customers.

We do not agree with Edison's contention that it is reasonable to aggregate fossil generation costs and revenues, in terms of tracking transition cost recovery. Instead, the assessment of whether assets and costs are economic or uneconomic must be made on an asset-specific basis. This methodology is required in order to carry out the netting principle; therefore, if a generation facility is likely to be economic on an overall basis, specific costs associated with that plant will not be eligible for treatment as transition costs. This principle has been debated thoroughly; indeed, we expressed our intent in this regard in D.97-06-060. A careful tracking of eligible transition costs and accrued revenues is necessary to ensure that we can confidently track recovery on an asset-specific basis. In order to apply the guidelines delineated in D.97-06-060, such detailed tracking is required. While § 367(b) requires a netting calculation, this certainly does not preclude asset-by-asset transition cost tracking, as Edison assumes. The expeditious, orderly recovery of transition costs, described in § 330(t) requires this approach.

6. Definitions

There is some argument as to basic definitions to be applied in this proceeding. Net book value has been defined in the Preferred Policy Decision and is used, but not defined, in AB 1890, specifically § 367(c). The term "sunk costs" is not defined in the Preferred Policy Decision, and is used only peripherally. It is neither used nor defined in AB 1890. PG&E suggests that defining such terms is not necessary at this time. We disagree. In such a complicated proceeding, it is pragmatic to ensure that all parties use the same terminology and understand such terms with particularity. By defining critical terms, we ensure that we are correctly applying the policy principles and foundation established in AB 1890 and the Preferred Policy Decision and at the same time, dispose of several contentious issues.

6.1. Net Book Value

Section 367(c) provides that uneconomic costs shall be "limited in the case of utility-owned fossil generation to the uneconomic portion of the net book value of the fossil capital investment existing as of January 1, 1998." Net book value was defined in the Preferred Policy Decision as follows:

> By "net book value," we mean the original cost recorded in the company's books for a particular asset less any accumulated depreciation and adjusted for deferred taxes, and any other asset or liability account which relates to the asset. (Preferred Policy Decision, mimeo. at 114, footnote 41.)

While PG&E does not believe it is necessary to adopt common definitions of these accounting terms, PG&E, Edison, SDG&E, and FEA recommend that this definition be used in determining transition costs. PG&E believes that this definition is consistent with § 367, but states that net book value does not encompass all of the costs that are eligible for transition cost recovery. In its Phase 1A policy brief, Edison clarifies that the phrase "any other asset or liability account which relates to the asset" would include all plant-related regulatory assets and liabilities, decommissioning, and deferred tax assets and liabilities. While Edison used the term "net book value" in A.96-08-006 in the more narrow sense as it is commonly defined, Edison now recommends that this definition be used only with the explicit recognition that costs included in the broader definition were eligible for recovery.

FEA recommends that the term include related decommissioning costs and costs of removal, as well as capital additions to generating facilities existing as of December 20, 1995, that the Commission determines are reasonable and should be recovered. ORA recommends that net book value be defined as the fully audited original costs recorded in each company's books for particular generation and generation-related plant, less any accumulated depreciation and adjusted for deferred taxes.

EPUC recommends that net book value be defined according to its common usage, i.e., as the original plant-in-service accounts costs less accumulated reserves for depreciation and amortization. EPUC believes that net book value is only a portion of "sunk" costs and is the definition underlying the language used in § 367(c). In its Phase 1A brief, EPUC explains that for purposes of AB 1890, net book value should not result in an amount that exceeds the original cost of an asset less depreciation and amortization. EPUC states that this counterintuitive result could occur if the overly-broad definition used in the Preferred Policy Decision is applied. For example, including other assets or liabilities associated with the plant (e.g., regulatory assets) or including going forward costs could lead to a higher value used to determine net book value. EPUC argues that the statute must govern and therefore the use of broad terms such as "any other asset or liability account which relates to the asset" would remove any meaning from § 367. EPUC further maintains that language in the Rate Restructuring Settlement can be used to clarify the Legislature's intent and that because the Rate Restructuring Settlement specifically distinguishes between the "net book value of fossil capital investment" and that of "fossil generation-related regulatory assets," the fact that § 367(c)(1) omits the latter phrase demonstrates the intent to limit fossil generation recovery to solely the net book value.

As discussed in the Phase 1A policy briefs, CEC recommends that we adhere to the definition of net book value, adopted in the Preferred Policy Decision and states that this definition is fully consistent with § 367. CEC also recommends that unless explicitly authorized in AB 1890 or eligible for recovery as an obligation or regulatory obligation, no going forward generation-related costs should be eligible for transition cost recovery. CLECA and CMA caution that adopting a definition does not eliminate the need to apply informed judgment to various cost categories, and furthermore, that this should be done on a case-by-case basis. While CLECA and CMA agree with the Preferred Policy Decision's definition of net book value, they believe that judgment must be applied to distinguish assets that are directly related to the generation asset from those that are indirectly or remotely related.

We will adopt a definition of net book value, but agree with CLECA and CMA's recommendations; i.e., we will apply informed judgment to the various cost categories for which the utilities seek transition cost recovery. We agree with Edison that the Legislature has forged California's electric restructuring policy in the context of the Commission's work in this regard, as acknowledged in § 330(d). Where specific terms are not defined, we must apply our broad knowledge of ratemaking principles and policy to interpret the statute in our administrative role to "supervise and regulate every public utility in the State and ... do all things, whether specifically designated in this part or in addition thereto, which are necessary and convenient in the exercise of such power and jurisdiction." (§ 701.) In this instance, it is reasonable to assume that the Legislature's intent in using the term "net book value" was based on the more narrow definition, because it refers specifically to the net book value of fossil *capital investment*.

However, because § 367 begins with a recitation of our duties in determining those costs and categories of costs for "generation-related assets and obligations, consisting of generation facilities, generation-related regulatory assets, nuclear settlements, and power purchase contracts...," it is unambiguous that such assets were intended to be eligible for transition cost recovery. We will apply the definition of net book value as original cost less accumulated depreciation and amortization in determining eligibility of various costs and cost categories for transition cost recovery, but will do so using the informed judgment and careful review recommended by CLECA. In order to implement this policy, we will fully and appropriately account for the impact of deferred taxes on the net book value quantification.

6.2. Sunk Costs

PG&E defines sunk costs to include generation-related costs that have occurred in the past, such as investments in generation-related plant and regulatory assets, or are fixed generation-related future obligations, such as fuel transportation costs and decommissioning costs. Edison thinks that sunk costs and net book value are equivalent terms, as provided in the Preferred Policy Decision; furthermore, Edison states that because AB 1890 does not use this term and because the statute governs which categories of costs should be recoverable as transition costs, it is not necessary to define this term for purposes of this proceeding. SDG&E believes that sunk costs include not only the net book value of non-nuclear generation and generation-related assets, but also obligations such as the unavoidable expenditure of funds for purchase power contracts and for other commitments related to generation operations.

ORA states that sunk costs are costs incurred in the past, which are non-recurring and best reflected by the net book value of utility assets. FEA asserts that sunk costs are generation-related costs that are fixed and unavoidable, but are not necessarily synonymous with transition costs that are to be recorded through the transition cost balancing account. FEA cites examples of sunk costs, including the original costs of generation facilities less depreciation, regulatory assets and liabilities which represent costs or obligations incurred in the past but which have not yet been fully recovered in rates, and generation-related costs associated with existing plant investments that will be incurred in the future, such as non-nuclear decommissioning costs.

CIU recommends that sunk costs in this context should be defined as capital costs only, using the net book value as of December 31, 1995, brought forward to January 1, 1998, and cites D.89-12-016 as defining sunk costs as those that have already been invested in plant. (34 CPUC 2d 55, 62.) Thus, CIU believes that PG&E's definition of sunk costs is too broad and that, although certain future costs are recoverable as transition costs pursuant to AB 1890, those costs cannot be considered sunk costs since they have not yet been invested in plant. EPUC states that sunk costs are those non-recurring generation facility, generation-related regulatory asset, nuclear settlement, or purchase power contract costs that were incurred and authorized for recovery in rates prior to December 20, 1995 and which were reflected in rates effective on June 10, 1996, with the caveat that none of these costs may be classified as "going forward" costs. EPUC believes that sunk costs and net book value are not synonymous and moreover, this definition is not relevant for transition cost eligibility purposes. EPUC recommends that we reject SDG&E's proposed definition of sunk costs because it is so broad as to render § 367 meaningless.

As addressed in the Phase 1A policy briefs, CEC defines sunk costs as those costs incurred in the past, in contrast to incremental and imputed costs. Such costs appear in accounting records, but are irrelevant for future operating decisions of the company. CEC agrees with ORA that sunk costs and net book value should be used synonymously. CLECA and CMA think that adopting a definition for sunk costs is not useful in this context, particularly because it is not used in AB 1890 and appears to be used synonymously with net book value in the Preferred Policy Decision. CLECA and CMA stress that just because a cost is categorized as sunk does not automatically mean that it is eligible for CTC recovery.

We agree that, in this case, it is not particularly advantageous to adopt a definition of sunk costs. This term was used only peripherally in the Preferred Policy Decision and was not used at all in AB 1890. It is more useful simply to define the terms that are actually used in the statute, but in order to establish a commonality of terms in this proceeding, we will define sunk costs as those which have already been expended for capital investment purposes. In D.97-05-088, we implicitly defined sunk costs when we stated, "the sunk costs for which PG&E now seeks recovery represent its undepreciated capital costs in the plant." (D.97-05-088, mimeo. at p. 31.) We explicitly defined sunk costs as "costs which are already incurred that can no longer be avoided or reduced through a curtailment or reduction of output or by providing other means of furnishing the service." (*Id.*, p. 41.)

6.3. Going Forward Costs

In general, recovery of going forward costs must be achieved by means of market revenues. The term "going forward costs" is used in § 367, but is not defined by the legislation, which states that "[a]ll 'going forward costs' of fossil plant operation, including operation and maintenance, administrative and general, fuel and fuel transportation costs" must be recovered through market revenues or ISO contracts, with certain important exceptions. Section 390(g) addresses short-run avoided costs and also uses the term "going forward costs:"

> The term "going forward costs" shall include, but not be limited to, all costs associated with fuel transportation and fuel supply, administrative and general, and operation and maintenance; provided that, for purposes of this section, the following shall not be considered "going forward costs": (1) commission-approved capital costs for capital additions to fossil-fueled power plants,

> provided that such additions are necessary for the continued operation of the power plants utilized to meet load and such additions are not undertaken primarily to expand, repower or enhance the efficiency of plant operations; or, (2) commission-approved operating costs for particular utility-owned power plant units and at particular times when reactive power/voltage support is not yet procurable at market-based rates in locations where it is needed, provided that the recovery shall end on December 31, 2001.

Edison points out that going forward costs can only be incurred by investor-owned utilities when those utilities are providing fossil-fired electric generation, beginning on January 1, 1998. Edison also states, however, that the utilities will incur certain fossil generation-related costs on and after January 1, 1998, regardless of whether they are still providing fossil generation to the market, including environmental compliance costs, pensions, and certain post-retirement benefits which must be provided even if all gas-fired generation were to cease.

EPUC argues that going forward costs are not limited to only incremental, variable costs or expense-related, non-capital costs, but that the statute implies that all going forward costs, both fixed and variable, are to be excluded from transition cost recovery; i.e., all costs that are necessary for the continued or future operation, maintenance or termination of the facility must be recovered from Power Exchange or ISO revenues.

Again, we must define going forward costs for purposes of ensuring that transition cost recovery is in compliance with the law. As in our discussion of net book value, we will use the context of the Preferred Policy Decision to inform our understanding and interpretation of AB 1890. We define going forward costs as all costs necessary to continue to operate the plant or unit. Going forward costs may include both fixed and variable costs. This interpretation most closely matches the standards articulated in the statute and our own preference for market recovery of such costs.

In D.97-08-056, our unbundling decision, we found that the definition of "going forward costs" was not limited to incremental costs and we recognized that, over time, all successful competitors must recover all costs, including fixed costs. It is for those reasons that we declined to allocate all fixed costs to distribution customers, which would then create a competitive advantage for the IOUs. (D.97-08-056, mimeo. at pp. 22-23.) Therefore, going forward costs will be defined as all costs that are necessary for the continued or future operation of the plant or unit, and include, but are not limited to, all costs associated with fuel transportation and fuel supply, administrative and general, and operation and maintenance, with the statutory exceptions established in § 367(c)(1) and (c)(2).[12]

6.4. *Must-run Generating Plants*

As CIU explains, "must-run" has been used as a general term to distinguish generating plants (or units within plants) that must be available to provide energy or ancillary services (in particular, reactive power/voltage support, one of a number of ancillary services) on a localized basis in order to maintain grid reliability.[13] Several aspects to the must-run determination must be considered. First, units may be deemed must-run for locational purposes; i.e., these units are within an area constrained due to transmission congestion and must be run to provide energy within the constrained area because sources of generation outside the constrained area do not have access to that area, because of transmission congestion.

Second, units may be deemed must-run for reliability purposes. These units provide voltage control and reactive power. These units are designated must-run for reliability purposes due to the requirements of the grid system for voltage and stability. To add to the complexity, units may serve dual functions. FERC has confirmed that the ISO should determine which plants are needed to provide reactive power/voltage support and when, because the ISO "will have the necessary information and technical expertise to make the determinations, and it will have no

[12] In D. 97-09-048, our decision on capital additions, we determined that capital additions occurring after January 1, 1998 to must-run plants should be recovered from payments under the ISO reliability contracts or Power Exchange revenues.

[13] We distinguish here between must-run and must-take resources. Must-take resources were defined in the Preferred Policy Decision and include QFs, nuclear, hydro-spill, and preexisting power purchase contracts with minimum take requirements.

incentive to discriminate among generators." (*Pacific Gas and Electric Company*, 77 FERC ¶ 61,265, December 18, 1996).[11]

On March 31, 1997, the ISO Trustee submitted descriptions of three types of Pro Forma Master Must-Run Agreements as part of its Phase II filing at FERC. The agreements are identical for PG&E, Edison, and SDG&E. As stated above, the ISO will determine which plants are must-run. According to the Phase II filing, the ISO intends for the must-run agreements to be temporary measures to be replaced as soon as possible by purchases either by solicitation or through the open market. The ISO recommends that it be authorized to terminate any must-run agreement upon 90 days' notice if it finds a less expensive source to supply this reliability power. It is important to emphasize that FERC may, of course, reject or modify these recommended agreements. However, it is pertinent to consider the interaction of such contracts and transition cost recovery. As a general rule, if the ISO agreements allow costs to be recovered as an ISO expense, they should obviously not be recoverable as transition costs.

Under all three agreements, the designated must-run units receive payments for start-up, fixed, and variable costs. Fixed costs include both a portion of existing rate base and incremental capital costs deemed acceptable by the ISO. We described these proposals in D.97-09-048:

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[11] FERC included the following discussion in its December 18, 1996 order:

> "Must-run generating units: These are units that must be dispatched during certain hours for reliability purposes, regardless of the units' bids. As a result of...physical limitations, during those hours, markets are sub-divided and isolated. Must-run units could be considered an extreme case of horizontal market power where, due to system conditions, the geographic market is so reduced that the system operator must run the units in order to satisfy demand that is assumed to be unresponsive to price. The operators of these units would have market power because there are no other alternatives. Therefore, if they had market-based rates, they could bid very high prices and the ISO would have to dispatch them at those prices." (*Id.* at pp. 62,076-77.)

> To summarize, the ISO proposes three types of reliability contracts, identified as Agreements A, B, and C. Agreement A assumes that the plant is economic and the ISO simply purchases needed resources at market prices. The owner can sell additional resources over and above the needs of the ISO (e.g., spinning reserves, voltage support, energy) into the Power Exchange. Agreement B provides for negotiated terms whereby the owner may have the right to collect revenues above what it might otherwise get above a market-based rate. In particular, Agreement B provides for a fixed cost payment and operating cost payment up to 100% of the cost of providing the needed must-run services to the ISO. Agreement B allows the plant to operate during hours when not needed by the ISO, but credits most of the profits from such operations to the fixed cost component. Agreement C is a cost-of-service contract for uneconomic units that must run for reliability reasons and are not likely to run during other hours. The units under this agreement are prohibited from supplying power during hours when the ISO does not need them. (D.97-09-048, mimeo. at p. 14.)[15]

As proposed, with a 90-day notice period, a plant owner may request a transfer to Agreement B or Agreement C. In addition, the ISO may transfer a plant to Agreement B or a negotiated version of that contract, on its own initiative, with 90 days notice. If the ISO refuses the owner's request, the existing agreement ends and the unit is no longer must-run. If the owner wishes to switch to Agreement B, the ISO can require that the owner negotiate to be paid any share of fixed costs that would be larger than would have been paid under Agreement A.

On October 30, 1997, FERC issued its "Order Conditionally Authorizing Limited Operation Of An Independent System Operator And Power Exchange, Conditionally Authorizing Transfer of Control Of Facilities On An Interim Basis To An Independent System Operator, Granting Reconsideration, Addressing Rehearings, Establishing Procedures and Providing Guidance," Pacific Gas and Electric Company,

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[15] We note that an application for rehearing of D.97-09-048 has been filed by PG&E. The determinations of this opinion do not prejudge the issues raised in that application for rehearing.

San Diego Gas & Electric Company and Southern California Edison Company, Docket Nos. EC-96-19-001 *et al.*, 81 FERC ¶ 61,122, 1997). In this order, FERC provides interim and conditional authorization under sections 203 and 205 of the Federal Power Act to the ISO and the Power Exchange to commence their operations, including interim conditional authorization of market-based rates for the Power Exchange.

FERC has accepted the pro forma Must-Run Agreements for the interim period, subject to certain modifications. FERC has required that the ISO file changes to the Agreements, as the ISO has proposed to do, by October 31, 1998, at which time FERC will re-evaluate the Agreements.[16]

For our purposes, we need only define must-run units in terms of which operating costs of which plants are eligible for transition cost recovery, pursuant to § 367(c)(1). Non-must-run plants are those generating plants which are not required to be available by the ISO for reliability purposes. The specific language of § 367(c)(1) makes it clear that the only units to which the statute refers are those units providing reactive power/voltage support, i.e., those units which must be run to support the reliability of the grid. We note that the precise language used in § 367(c)(1) confirms the wording of the Preferred Policy Decision, in which we determined that it is necessary to "severely limit... utilities' ability to obtain operating costs through the transition cost balancing account for their nonnuclear units" and determined that "[t]he only operating costs eligible for that account must be demonstrably necessary for reactive power/ voltage control." (Preferred Policy Decision, mimeo. at p. 100.) In addition, we determined that it was necessary to limit transition cost recovery of operating expenses in order to mitigate cross-subsidization and prevent utilities from exploiting regulated

[16] FERC has not yet ruled on the selection of must-run units because the selection and criteria used for selecting units for must-run status has not yet been filed by the ISO. When this is filed, FERC will evaluate the selection of must-run units based on certain criteria, including an agreement in principle that the ISO should consider all costs when selecting units for must-run status, including stranded costs. (*Id.*)

markets to obtain leverage in competitive markets. (Preferred Policy Decision, mimeo. at p. 102.)

6.5. Obligations

Both AB 1890 and the Preferred Policy Decision refer to "generation-related assets and obligations." Although not addressed to any extent in Phase 2, this term was defined by various parties in Phase 1A. Again, defining this term with specificity will assist us in our policy determinations. The Preferred Policy Decision specifically cites regulatory obligations as a category eligible for transition cost recovery. Regulatory obligations are

> "primarily related to various deferred costs and outstanding balancing account balances 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...but *these amounts should relate only to the generation assets affected by this restructuring.*" (Preferred Policy Decision, mimeo. at pp. 133 - 134, emphasis added.)

Contractual obligations are also defined in the Preferred Policy Decision in conjunction with QF contracts and other power purchase agreements. Section 367 refers to generation-related assets and obligations. Although "obligations" is not defined in § 367, again, we refer to the Preferred Policy Decision to frame the context in which legislative discussions were held and to enlighten our determinations. While AB 1890 discusses contractual obligations specifically, we cannot infer that regulatory obligations were intended to be excluded from transition cost recovery. In interpreting the statute, we will follow the California Supreme Court's guidance that:

> "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.)

Furthermore, we have stated in D.97-06-060 that because there is no specific reference to accounting methodology in AB 1890, we rely on our knowledge of current ratemaking practices, common sense and our duty to further the public interest in carrying out the mandates of the law. We find that both regulatory obligations and contractual obligations are eligible for transition cost recovery, in conformance with § 367. However, we will carefully review each claim for transition cost recovery in this category to determine whether such assets and obligations are, in fact, generation-related, unavoidable, and uneconomic.

7. 150 Basis Points Mechanism

The Preferred Policy Decision considered the recovery of transition costs, including operating costs:

> "All other costs of running [fossil fueled] units, including capital costs not yet incurred, will be subject to recovery through the prices received from the Exchange, with one limited exception. For those units that are primarily needed for reactive power/voltage control, if the costs of running these units (including capital costs not yet incurred) exceed the Exchange clearing price, utilities may seek partial recovery of operating costs up to the year 2003, subject to performance-based ratemaking, until or unless market based prices for reactive power/voltage control are set by the FERC. Further, if no recovery for reactive power/voltage control is sought and the Exchange clearing price exceeds the costs of running these units (including capital costs not yet incurred), utilities may retain profits providing up to 150 basis points above their authorized return for distribution rate base. Any further profits will be used to reduce CTC." (Preferred Policy Decision, mimeo. at p. 135.)

We determined in D.94-04-042 that the 150 basis point mechanism does not apply to non-must-run units:

> "AB 1890 addresses capital additions, but is silent on the 150 basis points allowance described above, other than for PG&E. Section 367(c)(1) provides that earnings from PG&E's reactive power/voltage support

> plants or units will be retained by PG&E and not used to offset transition cost recovery. A question that arises is whether fossil units which are not deemed needed for reactive power/voltage support...are eligible for the 150 basis points allowance. Edison's and PG&E's applications reflect the position that these units are eligible. We hold, however, that they are not. (D.97-04-042, mimeo. p. 17.)
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> * * *
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> "We intend that the 150 basis points allowance which was adopted in the Preferred Policy Decision will be applied only to fossil units which are primarily needed for reactive power/voltage control." (*Id.*, Conclusion of Law 3, p. 22.)

PG&E filed a petition in A.96-07-009 *et al.* (the PBR proceeding related to generation assets) for reconsideration of this issue. We affirmed our previous findings in D.97-07-037. We have previously stated that we would not address the merits of this issue in this proceeding, but we will consider the calculation of the 150 basis points mechanism and the interaction of this mechanism with transition cost recovery.

7.1. The Utilities

PG&E, Edison, and SDG&E are not claiming the 150 basis point mechanism for their must-run plants at this time. As discussed above, the development of this incentive or a similar incentive which would apply to non-must-run plants is to be determined in another proceeding. To the extent that such an incentive is applicable, PG&E recommends that the amount be determined at the time of market valuation based on costs tracked in plant-specific memorandum accounts. Edison and SDG&E recommend that the incentive be calculated annually if market revenues exceed incremental costs. Edison would include the calculation of an incremental capital cost credit prior to the application of the 150 basis point mechanism.

7.2. Intervenors

ORA recommends that any portion of the 150 basis point mechanism ultimately authorized in the PBR proceeding should be applied only after accounting for all going forward costs. TURN supports ORA's position and particularly emphasizes that the 150 basis points should be applied only after the utility recovers all of its operations and maintenance and fuel costs. TURN further recommends that no

150 basis point allowance should be paid for any plant asset if the utility is recovering any fuel-related costs for that plant in the transition cost balancing account. CIU believes that developing an implementation procedure here is premature, since it is unknown whether the substantive mechanism (as proposed by the utilities) will be approved in the generation PBR proceeding. EPUC recommends that this mechanism not be allowed for either must-run or non-must-run plants. To the extent that such a mechanism is developed, EPUC recommends that the applicable amounts be determined at the time of market valuation based on costs tracked in plant-specific memorandum accounts.

7.3. Discussion

We have previously determined that the 150 basis point mechanism applies only to must-run units. While the utilities dispute this approach, the merits of applying this incentive to the non-must-run units is not being considered here. We agree with ORA and CIU that it is premature to develop an implementation methodology at this time. If we reconsider this issue in the generation PBR proceeding, we can address implementation and interaction with transition cost recovery at that time. However, we provide some guidance in this area and find that should such an incentive mechanism be developed and adopted, all going forward costs must be accounted for with market revenues before any type of incentive mechanism should be applied.

8. Ratemaking treatment of gain or loss on sale

PG&E explains that the gain or loss on sale of depreciable assets has traditionally been flowed back to ratepayers through the depreciation reserve, while gains or losses related to non-depreciable property have been allocated to shareholders. PG&E believes that land must now be treated as depreciable property because of the language adopted in the Preferred Policy Decision and AB 1890. Therefore, PG&E proposes that all gains and losses realized through sale, spinoff, or appraisal of generation assets, including land, should flow back to ratepayers by way of the transition cost balancing account.

At the time of divestiture, Edison proposes to deduct the transaction costs of the sale from the sale proceeds. Edison would then compare this net sales revenue amount to the unamortized sunk cost of the asset at the time of sale to determine the net gain or loss on sale. Edison proposes to amortize this gain or loss on sale in the transition cost balancing account over the remaining months from the time of sale to December 31, 2001. Edison proposes that the unamortized portion of the gain or loss would be subject to the reduced rate of return and that the amortization would be accelerated according to the guidelines of D.97-06-060. Edison believes this approach is consistent with the requirements of § 367(b), which states in relevant part that uneconomic costs shall "be based on a calculation mechanism that nets the negative value of all above market utility-owned generation-related assets against the positive value of all below market utility-owned generation related assets." SDG&E agrees that the transition cost balancing account will provide the proper mechanism for netting the undepreciated book value against the market value.

Conceptually, we agree that the gain or loss resulting from sale of assets, including land, should now flow through the transition cost balancing account, but we see no reason to adopt Edison's approach of amortizing any gain over the remaining months of the transition period. The gain should simply be credited to the transition cost balancing account and the appropriate subaccount closed out.

We are currently authorizing auctions for assets undergoing divestiture. Pursuant to § 367(b), the valuation of these assets, in proceedings under §§ 455.5, 851, or otherwise, is final. As we move forward with these auctions, we must carefully review the transactions to ensure that the maximum amount reasonable under the circumstances of the sale is obtained to offset transition cost recovery, as is our duty under of AB 1890. For those assets which are retained by the utilities, we will develop market valuation procedures for appraisal, as discussed above.

9. Transition Cost Ratemaking and Market Power

In D.97-06-060, we adopted a transition cost balancing account for each utility and described in general terms how the recovery of various costs would be tracked in that account. In this decision, we discuss this recovery more specifically, particularly in terms of tracking the costs and revenues related to plants designated by the ISO as necessary for reactive power/voltage support and the non-must-run plants. As we have summarized, at least initially, the utilities are expected to have some locational market power, and this expectation has resulted in three call contracts being proposed to FERC. Agreements A, B, and C were described in Section 6. According to the proposals made at FERC, the ISO could terminate any existing ISO contract with 90 days' notice.

The actual tracking and accounting for transition costs and revenues associated with must-run units and non-must-run units is complicated; similarly, the issues raised in this area are complex and interrelated. First, we discuss transition cost ratemaking in terms of tracking and recording costs and revenues, recording net book value and depreciation, and applying various revenue crediting mechanisms. Next, we address the interaction of transition cost recovery and market power concerns in the context of transition cost ratemaking. We will explain the parties' positions in each of these areas and then discuss our determinations concerning transition cost ratemaking as a whole.

9.1. Tracking and Recording Costs and Revenues

PG&E proposes that prior to market valuation, all market revenues less operating costs be tracked in plant-specific memorandum accounts. At the time of market valuation, any credit balances resulting from operating profits would be credited to the transition cost balancing account. PG&E states that it reserves the right to seek recovery of debit balances for the must-run plants and would ask that we review the reasonableness of such recovery.

PG&E contends that based on the full context of § 367(c)(1), for fossil generating plants, it is the uneconomic portion of the net book value of the capital investment as of January 1, 1998,, and necessary capital additions to maintain the facilities through December 31, 2001 found reasonable by this Commission, which are recoverable from all customers on a nonbypassable basis. In addition, PG&E asserts that operating costs such as operation and maintenance (O&M), administrative and general, and fuel and fuel transportation costs are recoverable as transition costs if they are incurred while providing must-run services for the ISO and the plant is otherwise authorized to recovery market-based rates. PG&E thus believes that the implication is that if ISO contracts do not adequately cover the fixed and operating costs, such recovery may be sought elsewhere, including through the transition cost balancing account.

PG&E states that it has not created any subaccount in the transition cost balancing account to recover the operating expenses for non-must-run plants. PG&E intends to track fixed and variable operating costs and revenues for both must-run and non-must-run plants in separate memorandum accounts until market valuation occurs for each plant. PG&E proposes to track operating expenses for both non-must-run and must-run plants based on actual, recorded fuel costs and to track other expenses according to allocations adopted in A.96-12-009 *et al.* Tracking these costs and revenues will allow PG&E to compute the credit amount, if any, to account for revenues in excess of operating expenses for both the must-run and non-must-run plants. PG&E proposes that the resulting credit, if any, accrue to the transition cost balancing account, but PG&E recognizes that it is at risk for costs to the extent that operating expenses exceed revenues for non-must-run plants.

PG&E disputes CIU's contention that all capital costs associated with must-run plants with contracts with the ISO should be recovered only from the ISO revenues. PG&E contends that this would be contrary to § 367(c) unless it was assumed that such costs were economic. PG&E maintains that CIU's concerns are based on whether the mixture of transition cost recovery and ISO revenues could lead to double recovery of these costs, which PG&E asserts are ameliorated by its tracking proposal, since the ISO revenues would be credited back to transition cost recovery.

Edison recommends tracking all costs and revenues in fossil subaccounts of the transition cost balancing account, based on recorded amounts. These entries would include all plant-related capital costs, O&M costs, fuel costs, dispatch costs for gas, and ISO and Power Exchange revenues. Edison proposes to use recorded costs even for those cost categories that are subject to separate reasonableness reviews and that may be subject to pending reviews when the entries to the transition cost balancing account are being determined. Edison believes this is necessary because costs must be recovered prior to December 31, 1997 and such reasonableness reviews can be lengthy.

However, Edison states that the costs to be recovered through the balancing account would not exceed the sum of costs eligible for recovery. Edison explains that its proposal includes the relevant costs associated with must-run units as part of the costs eligible for recovery through the transition cost balancing account and establishes a crediting mechanism which includes the revenues from the ISO for the must-run services. Edison recommends this approach because this methodology would not require modification if the structure of the proposed ISO agreements should be modified by FERC. Edison contends that this proposal provides the opportunity to recover costs eligible for transition cost recovery, but there is no double recovery.

Edison has proposed a complicated revenue crediting mechanism to ensure that all costs and revenues are debited and credited correctly. First, Edison defines net eligible transition costs (i.e., costs eligible for transition cost recovery) as plant-related sunk costs, incremental capital costs necessary to maintain the facility through 2001, fixed fuel and fuel transportation costs for contracts signed prior to December 20, 1995, and Commission-approved operating costs for must-run generation, net of the market value of emissions allocations and revenues from gas sales. Once this determination is made, Edison proposes calculating three different credits: 1) for both must-run and non-must-run units, a gas purchase credit, which is defined as the market (or dispatch) costs of gas less the actual variable costs of gas; 2) an incremental capital cost credit to be applied to the non-must run units, and 3) a Power Exchange/ISO revenue credit to be applied to the must-run and non-must-run units. Edison proposes allocating the Power Exchange/ISO revenues net of going forward costs for the non-must-run units first to the incremental capital cost credit, the 150 basis points earnings mechanism, and then to the Power Exchange/ISO revenue credit (non-must-run). For the must-run units, Edison proposes that Power Exchange/ISO revenues net of going forward costs not found eligible for recovery through the transition cost balancing account be allocated to the Power Exchange/ISO revenue credit (must-run). The gas purchase credit, incremental capital cost credit, and Power Exchange/ISO revenue credits are then added together. If this result is positive, the amount is credited to offset costs eligible for transition cost recovery.

Edison contends that ORA's proposal to exclude sunk costs associated with must-run generating units from the transition cost balancing account has no applicability to must-run generation undergoing divestiture. In addition, Edison contends that it is only the future avoidable costs of a unit rather than the sunk costs, that are relevant in deciding whether it is efficient to replace that unit with a new entrant; therefore sunk costs are irrelevant in making economically efficient decisions. Edison agrees with CIU that § 367(c)(1) does not apply to Agreement C, because under this agreement, owners are not allowed to participate in the competitive market. Edison also agrees that the utilities should not have the opportunity to double recover costs, but believes this problem is averted by separately identifying the costs recoverable through the transition cost balancing account and then including the revenues received under the ISO must-run contract as a form of revenue in determining the Power Exchange/ISO revenue credit.

SDG&E proposes to record must-run costs and revenues in the transition cost balancing account while under Agreement A or until such time as Agreements B or C become available options. At that time, the accounting treatment would change to a memorandum account to be trued-up as part of the market valuation process. SDG&E proposes that the costs be audited and the revenue treatment be reviewed annually for those costs and revenues receiving balancing account treatment. SDG&E states that must-run costs should include those fixed costs required for maintaining plant availability requirements and the variable costs incurred as the units are dispatched. SDG&E contends that the proposed must-run agreements do not change the language of § 367(c)(1),which specifically allows for transition cost recovery of Commission-approved operating costs of those plants deemed by the ISO as needed for reactive power/voltage support.

For non-must-run units, ORA recommends that crediting Power Exchange revenues in excess of going forward costs to the transition cost balancing account. Consistent with its preferred methodology, ORA contends that going forward costs include all fuel, O&M costs, administrative and general costs, and depreciation and return on off-site common and general plant and capital additions. In contrast to PG&E and Edison, ORA proposes that no fuel or fuel transportation contract costs be included in the transition cost balancing account. These costs should be recovered from the Power Exchange and ISO to the extent possible. For Edison, if Power Exchange revenues are insufficient to cover all fuel, O&M, and capital additions costs, ORA recommends that only the fuel costs associated with fixed demand charge or take-or-pay provisions should be recoverable through the transition cost balancing account, and then, only to the extent that such fuel costs are uneconomic. This amount would be limited to the difference between Power Exchange revenues and all going forward costs, including capital additions. If the Power Exchange revenues exceed all these costs, no fuel costs could be added to the transition cost balancing account and a revenue credit would be available.

For must-run units, ORA recommends that the ISO revenues in excess of going forward costs should accrue to the utility and should not be credited to the transition cost balancing account unless the unit's must-run contract is terminated. Any profits should be tracked in a memorandum account should this event occur. ORA asserts that placing the fixed costs of must-run units in the transition cost balancing account would create a locational market power problem and inhibit the development of competitive markets for must-run reliability power. If the plant owner knows that fixed costs are covered in the balancing account, the owner may be inclined to accept less than full recovery of fixed costs through a must-run agreement. This, in turn, could create a locational market power problem by inhibiting market entry by new units in the same geographic area. ORA argues that because proposed Agreements B and C provide the plant owner with the opportunity to recover all fixed capital costs, including sunk costs, the sunk costs of must-run units should not be included in the transition cost balancing account. Once the agreement is terminated, the fixed capital costs associated with that plant should be calculated as the net book value as of January 1, 1998 less the fixed capital costs recovered under the reliability contract from must-run payments or from market revenues. This amount would then be booked to the transition cost balancing account. ORA thus recommends that while Agreement A may not cover all capital costs, any shortfall should be remedied by negotiating a transfer to Agreements B or C, rather than by guaranteeing recovery through the transition cost balancing account. ORA recommends that costs and revenues used to calculate profits should be tracked separately in memorandum accounts for non-must-run units and must-run units, which would then facilitate reasonableness reviews.

TURN states that operating costs of the must-run and non-must-run units are not eligible for transition cost recovery, but are going forward costs. To the extent that costs in excess of the Power Exchange prices are recovered through the ISO, they should be recovered from customers in transmission rates, rather than through transition cost recovery.

CIU asserts that there is no utility right to reserve the option to seek recovery of debit balances for must-run plants, unless that plant is actually called upon for reactive power/voltage support (and not any other "must-run" purpose) and the ISO fails to fully compensate the utility for such use. CIU states that § 367(c)(1) provides only limited options for transition cost recovery for must-run plants and contends that the utilities do not distinguish particular reasons for a plant being must-run, which could include purposes other than reactive power/voltage support, as described in the statute. CIU further maintains that to the extent the ISO limits payments to plants or units providing reliability support, it is not certain that the utilities have the right to seek recovery of additional costs through the transition cost balancing account. CIU believes that what is paid according to the ISO agreements must be considered sufficient to provide for the availability of resources to meet must-run needs related to reactive power and voltage support; therefore, there should be no additional recovery of operating costs through the transition cost balancing account. In addition, CIU asserts that because Agreement C does not allow for market-based rates and is cost-of-service based, § 367(c)(1) would not allow recovery of operating costs for plants covered by Agreement C.

EPUC recommends that generating units designated for reactive power/voltage support should not receive any transition cost recovery for any costs incurred during particular hours when the ISO did not require the unit to operate in order to provide this support. Thus, EPUC recommends that the accounting for these must-run units must ensure that all going forward costs are ineligible for transition cost recovery during the particular hours these units are not needed by the ISO for local reliability/voltage support. EPUC suggests that for purposes of transition cost accounting, revenues sufficient to cover costs should be imputed to each utility, thus ensuring that the daily net revenues are always greater than zero. EPUC believes that over a daily period, this approach is more likely to ensure that there is no systematic bidding below cost into the Power Exchange.

9.2. Recording net book value and depreciation

PG&E plans to track monthly recorded rate base for its fossil generation power plants, beginning January 1, 1998. These recorded rate base amounts will be based on eligible recorded plant, net of accumulated depreciation and recorded inventory balances, adjusted for accumulated deferred taxes. PG&E also proposes to ratably amortize generation-related assets and obligations. PG&E proposes that the recorded rate base balances reflect the amortization of uneconomic plant and plant-related costs, based on the 48-month schedule adopted in D.97-06-060.

Edison suggests basing the January 1, 1998 entries to the transition cost balancing account on recorded plant, depreciation reserve, and deferred tax balances as of that date, in order to maintain consistency among entries and related accounts. Edison proposes this approach for post-1995 capital additions, despite the fact that such additions will be reviewed in a separate proceeding, and recommends making adjustments, if necessary, to true-up the balancing account once final determinations have been made in that proceeding. Edison agrees that it is reasonable to use the 1995 year-end net book value amounts to begin the amortization schedule, as proposed by ORA, but recommends that the associated depreciation and deferred tax computations must also reflect year-end 1995.

SDG&E explains that it will reflect the amortization of the uneconomic portion of eligible plant using the 48-month amortization period adopted in Phase 1 and clarifies that as transition revenues are applied against these costs, generation rate base will be reduced on a comparable basis.

ORA does not agree with utility proposals to record and amortize the economic or uneconomic sunk costs of both must-run and non-must-run plants in the transtion cost balancing account. ORA recommends that only non-must-run sunk costs should be amortized in the transition cost balancing account. For must-run plants, ORA proposes that these sunk costs be amortized in the transition cost balancing account only until Agreements B or C become available and after such contracts are terminated for a particular unit.

9.3. *Revenue Crediting Mechanisms*

Revenue crediting mechanisms address how to apply each utility's revenues from the sales of electricity and ancillary services to its various costs. Neither PG&E nor SDG&E proposes any revenue crediting mechanisms. PG&E explains that its approach of using memorandum accounts to track the difference between operating expenses and revenues for both must-run plants and non-must-run plants, and to credit the revenues in excess of expenses and any allowed 150-basis point provision will eliminate the need for any revenue crediting mechanisms. PG&E is not claiming the 150 basis point mechanism for its must-run units, nor is PG&E planning on retaining any earnings from the operations of the reactive power/voltage support plants or units, although § 367(c)(1) allows those earnings for PG&E. As part of PG&E's proposal both in this proceeding and before FERC, that any excess revenues above operating costs would be credited to offset transition cost recovery. PG&E proposes to track costs and revenues through appropriate plant-specific memorandum accounts and then to do a one-time accounting at the time of market valuation of that plant to determine if there are any eligible costs that PG&E wishes to recover in the transition cost balancing account. PG&E recognizes that it must apply revenues from fossil plants which are in excess of costs to offset transition costs and proposes to do so in a memorandum account. PG&E also recognizes that operating costs and going forward costs of non-must-run plants cannot be included in the transition cost balancing accounts for recovery.

Edison explains that in general market revenues will be allocated to its revenue requirements, with any balance applied to reduce transition costs. Edison explains its approach to calculation of eligible transition costs as a series of interrelated steps. Edison goes through a multi-step process to derive its proposed revenue credit for non-must-run plants (with revenues deriving from both non-must-run gas plants and coal plants (all of which are non-must-run). Edison essentially would flow all its costs and revenues through the transition cost balancing account. Market revenues are first allocated to recover all going forward costs, then to incremental capital additions, then to its proposed 150 basis point earnback mechanism and finally to calculating a credit from the excess market revenues, if any, to be applied as a credit to the transition cost balancing account. Edison's proposal is similar for its must-run plants, except that no 150 basis point earnback is proposed.

Edison also states that because, in its filing at FERC, it has committed to a variable cost floor calculated over a two-week period on the revenues it can receive from its gas generation prior to divestiture, it is precluded from bidding below variable cost into the Power Exchange. Edison therefore disagrees with EPUC's contention that the revenue crediting mechanism never be permitted to go negative in any single day. Edison states that the reason the variable cost floor is defined over a two-week period is to consider the impact of the costs of starting and stopping a generating unit, which are generally committed to participate in a market over a multi-day period. In other words, Edison maintains that EPUC's proposed daily calculation provides too short a time frame for calculating the net revenue credit, because the utility may not recover its no-load and start-up costs on a daily basis.

Because we have not adopted a 150 basis point incentive mechanism for non-must-run units, ORA states that its proposed revenue crediting mechanisms and those of Edison are now not very different. ORA proposes a revenue crediting mechanism for all three utilities and wants to be certain that proper accounting of these mechanisms is established in the event the 150 basis point mechanism is adopted for non-must-run plants, such that all going forward costs are covered before any profits accrue to shareholders. ORA further wants to ensure that such mechanisms require that the utilities recover all going forward costs from market revenues in order to have the utilities bidding into the Power Exchange at fair levels. ORA proposes that its revenue crediting mechanism apply to non-must-run units and former must-run units whose contracts with the ISO have been terminated. Thus, for must-run units under Agreements B or C, ORA recommends that the utilities track costs and revenues in memorandum accounts to result in future revenue crediting if the unit terminates its ISO must-run contract during the transition period.

ORA explains that for a market to be sustainable, the market clearing price must be set high enough to allow economically efficient non-utility generators to recover all economic capital costs and operating expenses associated with owning and operating the unit over its lifetime. ORA fears that if the utilities can cover these costs through transition cost revenues and various revenue crediting mechanisms, this could result in the utilities bidding into the Power Exchange at an artificially low price. Thus, competitors would be disadvantaged, increasing the utilities' market power. Excess revenues result from the difference between bid prices and the market-clearing price and it is through this surplus that fixed capital costs and fixed expenses are covered. ORA explains that excess revenues remaining after paying operating costs are available to pay capital costs, including depreciation first, and then return on the asset. Therefore, ORA recommends that we should not allow transition cost recovery of economic costs, i.e., those costs that can be recovered through the market.

ORA maintains that these costs must be netted out of market revenues prior to crediting any excess revenues to the transition cost balancing account. Consistent with its position on these issues, as discussed more fully below, ORA advocates that economic fixed fuel costs and the depreciation and return on off-site common and general plant and capital additions also be subtracted from market revenues prior to any revenue crediting. For sunk generating plant, ORA maintains that as the unit ages, the market value decreases, thus increasing transition costs. The depreciation on the economic portion of the plant, then, should be recoverable from market revenues, which ORA believes will parallel the decrease in market value.

ORA explains that another reason for crediting excess market revenues to offset transition cost recovery is that prior to market valuation, the uneconomic portion of the plant is not known. Thus, the reduced rate of return can be applied only to the entire plant and charged to ratepayers through the CTC. The market revenue credit would compensate for this so that ratepayers would pay a return only on the uneconomic portion of the plant, while the market paid for the return on the economic portion. The revenue credit implicitly includes this return on the economic portion and would then offset the return on the total plant, because this is part of the transition cost revenue requirement.

EPUC recommends specific modifications to Edison's revenue crediting proposal. As discussed in Section 13, regarding fuel and fuel transportation contracts, EPUC maintains that Edison's gas purchase credit should have a safeguard and never be recorded as less than zero. Without this safeguard, EPUC believes Edison would recover more than the statute allows for the uneconomic portion of the fixed gas costs.

9.4. Market Power and Transition Cost Recovery

The Assigned Commissioners issued a ruling on February 4, 1997, which established, among other things, that transition cost recovery raises fundamental questions related to competition and the interaction of transition costs with the operation of the Power Exchange:

> "While it is FERC which will decide the particular horizontal and vertical market power issues and appropriate mitigation measures, this Commission has stated clearly in several forums that it will be actively concerned with market power in its own proceedings. (Preferred Policy Decision, mimeo. at 20; Roadmap 2 decision, mimeo. at 9.) Therefore, as we begin Phase 2 of the transition cost proceedings, we will ask parties to consider and respond to issues related to transition cost recovery, market power and incentives which may be operating in the short term and the long term. For example, one such issue we wish to consider is whether recovery of transition costs under the rate freeze creates any perverse effects in the Power Exchange; i.e., does the existence of headroom lead to

> predatory pricing, and if so, how can this effect be mitigated."
> (Joint Assigned Commissioners' Ruling, February 4, 1997, at p. 9.)

Several pages of written testimony addressed this issue. In consultation with the Assigned Commissioners, the ALJ struck much of the testimony which related to specific findings that must be made by FERC or which would require findings that were not relevant to this proceeding. (RT: 1319-1320.)

PG&E maintains that there are no market power issues to address regarding transition cost recovery, because all such issues are being considered at FERC. PG&E also states that because Edison plans to divest all of its gas-fired plants and PG&E has now pledged to divest 100% of its fossil plants, market power concerns would be short term in nature.

Edison disputes CIU's assertion that must-run units receiving fixed-cost recovery through call contracts with the ISO will have a competitive advantage over other generators bidding into the Power Exchange. Edison believes that this allegation is not relevant to this proceeding because these issues are being considered at FERC and because any concerns would be short-lived, due to its agreement to divest its gas-fired plants. Edison argues that in a competitive market, the recovery of fixed costs should not influence short-term pricing decisions. Edison agrees with SDG&E that, because FERC will only grant market-based pricing authority if the utility demonstrates that market power has been adequately mitigated, utilities will not have the market power to depress market prices. Edison explains that the transition cost mechanism will not provide for the recovery of operating losses, because going forward costs (other than for must-run units) must be recovered from the market.

Edison disputes ORA's proposal to exclude sunk costs associated with must-run generation from the transition cost balancing account, because this proposal does not recognize that sunk costs are irrelevant in making economically efficient decisions and because it should have no applicability to must-run generation undergoing divestiture.

SDG&E maintains that nothing in the transition cost recovery mechanism would influence its market power position. SDG&E explains that while during the rate freeze, SDG&E prefers that Power Exchange prices be lower in order to maximize its available headroom, this should not be construed as predatory pricing. SDG&E recommends that any policy regarding competition must exist to protect competition and consumers, rather than particular competitors. SDG&E observes that the rate freeze should eliminate concerns regarding predatory pricing. Predatory pricing is defined in this context as a market power concern arising from a hypothetical possibility that a seller with large market share would sell below variable cost in order to drive competitors from the market. At that point, the seller would recoup its losses by charging exploitative high prices. If there is no ability to recoup lost profits by subsequent high prices, consumers would not be damaged and would benefit from the period of low bidding into the Power Exchange. Furthermore, SDG&E contends that, because of its small size, it lacks market power, other than local market power in the San Diego Basin which would be mitigated by the proposed must-run contracts.

ORA asserts that market power can result when costs that should be recovered in the marketplace are in fact recovered through the transition cost mechanism. This could lead to depressed bidding prices into the Power Exchange, leading to deflated market clearing prices, which could then disadvantage other competitors. ORA believes that this potential also exists in the ISO market for reliability services. Given that fewer producers will likely compete in local areas for reliability services, ORA contends that this is the more critical area. ORA recognizes that divestiture will mitigate many market power concerns in this area, but asks that the policy for transition cost recovery for must-run units (most of which are fossil) be established so as not to create or exacerbate any market power concerns.

ORA suggests that to mitigate such market power concerns in the ISO reliability market, no transition cost recovery should be allowed for must-run units. ORA explains that the proposed Agreements B and C are intended to grant full cost-of-service recovery, including sunk capital costs. Hence, if recovery of these costs is then permitted in the transition cost balancing account, there would be little incentive for the utilities to negotiate properly with the ISO. However, to conform to the requirements of

§ 367(c)(1), ORA would allow transition cost recovery for must-run plants during the first 90 days on Agreement A while a switch to Agreement B is being sought.

ORA urges us to require all non-must-run units to recover their going forward costs from the Power Exchange, as required by § 367(c). ORA recommends that while this is required by law only for fossil units, market power concerns prescribe that the going forward costs of hydroelectric and geothermal units which are retained should also be recovered from the market. ORA also recommends allowing transition cost recovery for Edison's uneconomic and reasonable fixed fuel and fuel transportation costs only to the extent that Power Exchange revenues do not cover all fixed and variable fuel, O&M costs, and administrative and general costs.

FEA urges us to ensure that the transition cost balancing account not include any costs which are not specifically required under AB 1890. Similarly, EPUC recommends that the proper standard to bear in mind in considering market power issues is that the market should be equal for all new market competitors, which cannot occur if utility assets are not at risk for going forward costs consistent with the requirements of § 367(c). EPUC maintains that the utilities' proposed accounting mechanisms and safeguards with regard to must-run operating cost recovery would lead to market distortions. EPUC strongly recommends that we ensure transition cost recovery for must-run units only at the particular hours when the unit is providing local reliability/voltage support and that otherwise such units not be permitted to distort the competitive market by bidding into the Power Exchange during non-constrained-on hours. EPUC asserts that the utilities' fossil units represent marginal generation much of the time and therefore, if the units bid their actual operating costs these units would establish the Power Exchange clearing price. EPUC fears that if must-run units can receive cost recovery through transition cost recovery, this would result in the market clearing price being set by a lower-cost producer and recommends that these distortions be avoided by ensuring that the costs of those must-run units which the utility chooses to place at market risk should be barred from transition cost recovery.

IEP explains that the rate freeze, the residual CTC calculation, and the existence of headroom all combine to create a strong incentive for the utilities to deflate

Power Exchange prices, which would then lead to dampened competition. Consequently, although the rate freeze protects consumers from high prices, IEP contends that they are still harmed because if competitors are driven from the market and new entry is discouraged, there will be no choice among energy service providers after the transition period. This lack of competition could then result in higher prices after the rate freeze, because there will not be competition to ensure that energy prices are driven down to marginal costs. IEP asserts that despite the fact that FERC has jurisdiction over the market power issues brought before that agency in regard to establishment of the ISO and Power Exchange, we are also obligated to consider these issues and their impact on competition.

IEP asks that we consider its proposals for market power mitigation in this proceeding, despite the fact that its prepared testimony regarding divestiture and the establishment of a total cost bidding floor was stricken. IEP is not necessarily suggesting we adopt its proposed solutions in this proceeding; rather we could order divestiture or adopt a bid floor in a separate proceeding. We affirm that the ALJ properly struck this testimony and we will not address IEP's proposed mitigation measures in this proceeding. This proceeding is complicated enough without considering additional complex issues that are being addressed elsewhere and will be decided in other forums. Furthermore, on July 30, FERC issued an order providing guidance to the ISO and Power Exchange governing boards and required the restructuring proposal to be refiled on August 15, 1997, along with various additional submissions, including various monitoring and mitigation proposals regarding market power. (FERC ¶ 61,128, mimeo. at p. 1.) It would be premature to address these issues in this proceeding.

9.5. Discussion

We fully support the idea that the linchpin of competition policy must be to protect competition and consumers, rather than individual competitors. In order to ensure that competition exists and to protect the incipient competitive generation market, we must ensure that no greater competitive advantage is afforded the incumbent utilities than any other competitor in the new market. As discussed in the Preferred Policy Decision, we have adopted transition cost recovery for several vital reasons, including acknowledging the regulatory compact in existence at the time investment decisions were made, and this policy has now been mandated by law. In implementing this policy, however, we are also compelled to ensure that we foster competition as the new competitive marketplace begins to function. It is for these reasons that we address the interaction of transition cost ratemaking and market power concerns.

We are disturbed by the idea of tracking all costs related to non-must-run and must-run units through the transition cost balancing account, whether various revenue credits are applied to those costs or not. Our concern centers on the possibility of allowing recovery of going forward costs through transition cost recovery, when that is contrary to the concept of fostering a competitive marketplace and is specifically prohibited by law, with only limited exceptions. Although accounting for such costs and revenues in memorandum accounts is cumbersome, we are prepared to require such tracking. The interaction of transition cost recovery and market prices is significant and may be critical to the successful operation of the marketplace.

We have stated many times that we wish to avoid administrative calculations of transition costs to the extent possible and prefer to rely on market mechanisms. We are spurred in this regard by the Legislature's affirmations that competition in electric generation is preferred to regulation because it will encourage innovation, efficiency, and better service from all market participants. (§ 330(c).) ORA's discussion regarding the treatment of excess revenues is important, although we disagree with its recommendations. We agree that market revenues from all sources, that are in excess of costs should ultimately offset transition costs. These revenue sources include all revenues from the Power Exchange and the ISO, but may also include revenues from other markets, or sources as may be determined in the future."[17]

On the whole, we agree with PG&E's approach, with certain modifications. We direct the utilities to establish separate memorandum accounts for non-must-run and for must-run plants. For the non-must-run plants, we will track the difference between costs and market revenues on a monthly basis. Any excess revenues will be credited to offset transition costs on an annual basis, in the following fashion. The revenues will be tracked in the memorandum account on a monthly basis and will be available to apply to costs incurred in other months. Any excess revenues accruing in a particular month will earn the reduced transition cost rate of return, rather than the commercial paper rate. We recognize the utilities' concerns that monthly postings of excess revenues to the transition cost balancing account could impact the recovery of costs incurred during plant outages when there may not be revenues to offset these costs. An annual crediting to the transition cost balancing account of any excess revenues addresses such concerns. At the same time, applying the reduced rate of return to these revenues is appropriate because this higher interest rate compensates ratepayers for carrying costs associated with transition costs that would otherwise have been reduced through monthly postings. No interest rate or rate of return will be applied to any debit balances in that account.

PG&E, Edison, and SDG&E should establish a Power Exchange Revenue Memorandum Account to track actual going forward costs on a plant-specific basis. PG&E has proposed to use this approach for fuel costs, but to base other operating costs on revenue requirements adopted in D.97-08-056. We prefer a more accurate approach. Information regarding operations should be readily available. The utilities should then

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[17] For example, currently pending before FERC are proposed ISO and Power Exchange tariffs for various markets, which will produce revenues from Supplementary Energy Bids, Ancillary Service Bids, Adjustment Bids (for congestion management), and Imbalance Bids. If approved by FERC, these revenues, or revenues from any other such as ISO or Power Exchange auctions approved by FERC, must be tracked for purposes of transition cost recovery.

credit the transition cost balancing account for any excess market revenues greater costs, including revenues from the ISO, Power Exchange and other retirement sources, as described above. If revenues are less than costs, no additional transition cost recovery is allowed, consistent with § 367(c), nor will any interest be allowed on debit balances in this tracking account.

In D.97-09-048, we determined that the costs of capital additions incurred after January 1, 1998 should be recovered from market revenues, rather than through transition cost recovery. We have allowed limited ex post facto reasonableness reviews of these expenditures for transition cost recovery if and only if the following four conditions are met: 1) the capital additions were made to ISO-designated must-run units and were necessary to continue operating the must-run unit during the transition (through December 31, 2001), 2) the capital additions were cost-effective compared to other options for maintaining plant operations through the transition and compared to other resources available to the ISO for system reliability, 3) the final ISO contracting options approved by FERC did not include provisions that would allow utilities to negotiate recovery of these costs and 4) the costs of capital additions could not be recovered in market prices for energy or ancillary services. Furthermore, we have determined that the ISO contracts afford the utilities the opportunity to recover the costs of capital additions needed to maintain system reliability. Establishing a procedure for this recovery at this Commission would be inefficient and could also give the utilities a competitive advantage over other providers of must-run units and thwart our objective of creating a level playing field.

Similar principles apply to recovery of operating costs. These contracts did not exist when AB 1890 was signed into law. The contracts have been proposed to FERC to ensure that the reliability of the grid will not be compromised. To the extent the ISO limits payments to plants or units providing reliability support, we do not agree that the utilities have the right to seek recovery of additional costs through the transition cost balancing account. Given the jurisdiction of FERC over the ISO, and the fact that FERC has allowed the ISO to make these determinations, the amounts paid according to the ISO agreements should be considered sufficient to provide for the availability of resources to meet must-run needs related to reactive power and voltage support; therefore, in general, there should be no additional recovery of operating costs through the transition cost balancing account.

We do not think that Agreement A should necessarily be subject to the § 367(c)(1) exception. Rather, we are persuaded that under the proposed Contract A, the ISO is paying for a pro rata share of the fixed costs of a competitive plant, as well as for its variable costs when the plant is called upon by the ISO for must-run purposes. This merchant plant is expected to recover its other costs in the marketplace. We must presume that the variable costs paid by the ISO for these purposes must be sufficient to recover the operating costs for those units needed for reactive power/voltage support at particular times. It is possible that under Agreement A, the utilities will not recover all operating costs related to reactive power/voltage support. Rather than seeking transition cost recovery, however, one solution is for the utility to negotiate with the ISO to move to Contract B. Agreement B provides specifically for recovery of fixed costs, which include sunk costs; therefore, to the extent that sunk costs are recovered through ISO revenues, there should certainly be no duplicate recovery through transition cost recovery. We agree with CIU that because Agreement C does not allow for market-based rates and is cost-of-service based, § 367(c)(1) would not allow recovery of operating costs for plants covered by Agreement C.

Certainly, the only instance in which we would even consider transition cost recovery for must-run plants is for those particular units operating at those particular times when the plant is actually called upon for reactive power/voltage support (and not any other "must-run" purpose), and the ISO contract has not provided recovery of operating costs, and the units are otherwise authorized to recover market-based rates. Therefore, while the task may be complicated, we must ensure that we can clearly track and distinguish the costs for those units designated by the ISO as necessary to operate at particular hours for reactive power/voltage support from units designated as must-run for any other purposes, in order to allow operating cost recovery for those units the guidelines of § 367(c)(1). The utilities will have the burden of clearly distinguishing and demonstrating particular reasons for a plant being operated for only reactive power/voltage support, consistent with the other criteria described in the statute. We will consider such recovery only for these units on Agreement A during the first 90 days of the transition period.

We are reluctant to flow these costs and revenues through the transition cost balancing account, because of the potential for double counting, despite Edison's assurances to the contrary. Instead, we prefer PG&E's proposal and direct each utility to establish an ISO Revenue Memorandum Account for its must-run plants and to track market revenues, as described for the non-must-run plants. We will review the memorandum accounts and their ultimate transfer to the transition cost balancing account, if appropriate, in the annual transition cost proceedings. This review process will provide the utilities with the assurance that, to the extent that uneconomic costs and operating costs of must-run units on Agreement A are not covered by ISO and other market revenues, they will have the opportunity to present and clearly prove the reasonableness of these costs to this Commission.

However, we do not agree with ORA that transition cost recovery of sunk costs for must-run units should be precluded. It is not clear that the ISO Agreements will provide for recovery of all sunk costs, although certainly a portion of sunk cost recovery will occur. In essence, the proposed contracts will allow for the "economic" depreciation and return on investment of these plants. We will account for this by crediting excess revenues to the transition cost balancing account.

FERC has accepted the pro forma Must-Run Agreements on an interim basis, but requires the ISO to file revised Agreements by October 31, 1998. These revisions include clarifications and modifications to Agreements A, B, and C. (Pacific Gas and Electric Company *et al.*, 81 FERC ¶ 61,122, 1997, mimeo. at p. 257.) These memorandum accounts will allow the necessary tracking to occur so that any required modifications to our procedures can be executed efficiently and easily.

One purpose of the memorandum accounts is to track the going forward costs and market revenues for particular assets and to verify that market revenues which are greater than costs are credited appropriately to the transition cost balancing account. Pursuant to the guidelines established in D.97-06-060, the transition cost balancing account will track current costs eligible for transition cost recovery, including scheduled amortization. The transition cost balancing account also tracks CTC revenues, the market revenues related to a particular asset less going forward costs, as discussed above, and market valuation credits.

In addition, we will establish procedures to complete the market valuation process as early in the transition period as possible. All generation assets owned by the utilities must be market valued by December 31, 2001, consistent with § 367(b), by divestiture, appraisal, or other form of sale. Nothing in the legislation, however, precludes us from requiring that this market valuation occur before that date. Early market valuation will ensure that the transition to a competitive generation market is completed as expeditiously as possible.

Initiating the market valuation procedures early in the transition has at least two important advantages. First, market valuation gives us the necessary information regarding economic and uneconomic costs for these assets and will assist us in ultimately determining both the final amount of transition costs allowed for generation plant assets and when the rate freeze can end. Second, once market valuation occurs and the rate freeze ends, it will no longer be necessary to track excess revenues accruing from market revenues.

Divestiture proceedings are well underway for PG&E and Edison. Edison plans to divest 100% of its gas-fired fossil plants and will retain its hydroelectric and coal plants. PG&E has now pledged to divest 100% of its fossil and geothermal plants. It is equally important to develop appraisal procedures for those plants which are retained by the utilities. We will initiate this proceeding by requiring PG&E, Edison, and SDG&E to file applications by March 2, 1998 which identify the plants they plan to retain, proposed guidelines for appraisal, and a proposed procedural schedule for addressing these issues.

The January 1, 1998 entries to the transition cost balancing account should be based on recorded plant, depreciation reserve, and deferred tax balances as of December 31, 1995, to maintain consistency among entries and related accounts. In other words, the net book value as of December 31, 1995, of eligible plant categories will be amortized over the 48-month transition period according to the guidelines established in D.97-06-060. These amounts will then be trued-up for 1996 and 1997 capital additions, because such additions will be reviewed in a separate proceeding. Adjustments and true-ups for depreciation will occur in the annual transition cost proceeding. These recorded rate base amounts will be based on eligible recorded plant, net of accumulated depreciation and recorded inventory balances, adjusted for accumulated deferred taxes. The initial recorded rate base balances will reflect the amortization of uneconomic plant, based on the 48-month schedule adopted in D.97-06-060. As provided for in that decision, assets should not be depreciated below market value, which will account for recovery of the economic portion of the depreciation in the marketplace. Amortization schedules should be recalibrated, as necessary. As the divestiture proceedings progress, many of our concerns regarding must-run plants will be eliminated through the market valuation process. The utilities may adjust the transition cost balancing account when assets are sold or market-valued to reflect the actual costs on the books. If decisions regarding capital additions are issued after the sale of a plant, the transition cost balancing account will be adjusted to reflect the outcome of those proceedings.

Because we have prescribed various guidelines in D.97-06-060 regarding order of recovery and acceleration, we are not as concerned about capturing the economic value of depreciation through the market. While we have determined that the net book value is eligible for recovery at the beginning of the transition period, we have also stated that each asset should be depreciated to its market value, but not below, and that recalibration of the amortization may then be necessary.

10. Transition Cost Audit

In response to an Assigned Commissioner Ruling issued August 1, 1996, the Commission Advisory and Compliance Division (predecessor to the Energy Division) coordinated the selection of an independent auditor to establish the net book value of the non-nuclear generation assets and other transition costs, as a starting point in determining the transition cost estimates. Mitchell & Titus, LLP and the Barrington-

Wellesley Group, Inc. were engaged to perform the audit and produce a report, "Agreed-Upon Special Procedures Review of Unrecorded Sunk Costs and Future Costs for PG&E, Edison, and SDG&E. This report was filed and served on March 21, 1997. The auditors issued an audit opinion on the recorded sunk cost balances of transition costs reported by the companies as of December 31, 1995. The audit opinion for each utility was qualified with respect to inventory balances, because of the auditors' inability to observe physical inventories on December 31, 1995. In addition, for PG&E, the audit opinion as of December 31, 1995 was qualified for the Western Area Power Administration (WAPA) regulatory asset balance of $137.1 million because of a scope limitation due to insufficient supporting information being provided by PG&E. The audit opinion for PG&E was also qualified for the QF Buyout regulatory asset account balance of $165.1 million, because approval is pending before the Commission. Other than these exceptions, the audit opinion for the recorded sunk cost balances as of December 31, 1995 was unqualified. Certain immaterial errors were identified at PG&E and Edison which did not result in a qualification of the audit opinion.

The auditors also reviewed unrecorded sunk costs as of December 31, 1995 and future cost balances projected as of January 1, 1998 and presented a report on these balances. The auditors questioned various costs of each utility in the following categories:

1. AB 1890 definition: The category includes costs questioned by the auditors because they are not in strict compliance with AB 1890.
2. Commission approval: The category includes costs incurred prior to December 20, 1995 that are not included in rates and have otherwise not been approved by the Commission.
3. Estimates and Assumptions: This category relates primarily to future costs, which were questioned because they were either based upon speculative assumptions or because the auditors could not adequately test the company's estimates.
4. Inadequate support: These costs are questioned because the company did not supply the information necessary to test the amounts included in the transition cost filing.

5. Company adjustments: This category reflects adjustments proposed by the company based upon information which became available after the date of the transition cost filing.
6. Accounting problems: This category represents costs which are questioned because of accounting errors or other reporting problems.

The following table shows the results of the auditor's review:

Summary of Questioned Costs by Category

(Dollars in Millions)

Description	PG&E	Edison	SDG&E	Total
Amount recorded on the Transition Cost Statement	$ 35,393	$ 34,239	$ 3,521	$ 73,153
Items not authorized specifically in AB 1890	$ 91	$ 64	$ 39	$ 194
Items Lacking Commission Approval	$ 81	$ 632	$ -	$ 713
Items that used questionable Estimates & Assumptions	$ 1,516	$ 2,313	$ 24	$ 3,853
Items lacking adequate Support	$ 1,917	$ 444	$ 10	$ 2,371
Adjustments made by the Utilities	$ -	$ -	$ (3)	$ (3)
Account Problems	$ 496	$ -	$ -	$ 496
Total Questionable Items	$ 4,102	$ 3,453	$ 70	$ 7,625
Adjusted Transition Cost Statement Amount	$ 31,291	$ 30,786	$ 3,451	$ 65,528

The auditors question $7.6 billion, or approximately 10%, of the utilities' total transition cost estimates. As a whole, the audit report has served its purpose of providing the audited net book value for transition cost recovery as of December 31, 1995 and we accept these balances as the starting point for transition cost recovery, recognizing that as proceedings are completed for capital additions for 1996, 1997, and the first three months of 1998, these net book value amounts will be adjusted. We address particular cost categories for starting points as of January 1, 1998 in relevant sections throughout this decision. While the auditors questioned the eligibility of certain cost categories and accepted the eligibility of others, it is up to this Commission to make those determinations. The audit report addressed certain cost categories which will not be considered in this decision, including capital additions, QF contract restructurings and buyouts, employee-related transition costs, and restructuring implementation costs.

The utilities responded to the audit report on April 10, 1997. In general, PG&E, Edison, and SDG&E find the audit findings thorough, accurate, and reasonable. To the extent that costs are questioned because estimates have been used, the utilities explain that it is the actual costs which are relevant. The auditors' findings regarding questioned cost categories are discussed in the pertinent topic area throughout this decision. Edison recommends that, in the future, any similar audits allow for the opportunity for a factual review prior to the issuance of the audit report. We agree that this is a desirable step which should be undertaken to the extent possible, given the time constraints involved in various proceedings.

PG&E requested that a supplemental report be issued regarding its WAPA regulatory assets, QF buyout regulatory asset, and hydroelectric negative net salvage. This request was granted and the supplemental exhibit was filed on June 27, 1997. PG&E filed comments on this supplemental report on July 7, 1997. These audit findings and PG&E's responses are addressed in the relevant sections below.

ORA recommends that a regulatory audit be performed for non-nuclear generation sunk costs being considered for transition cost recovery. We are satisfied with the audit procedures, which were performed in accordance with the directives of the ACR issued on August 1, 1996, and with the scope of the audit as outlined in the auditors' workplan in Exhibit 44. No additional regulatory audit is necessary.

11. Fossil Generation Transition Costs

11.1. Fossil Generation Rate Base and Net Book Value

Each utility has presented an estimate of net book value of its various generation plant assets, as of January 1, 1998. The estimates of net book value or net plant in service include amounts which have been verified as of December 31, 1995 and forecast for January 1, 1998. We are not addressing capital additions in this proceeding; therefore, the final net book value amounts as of January 1, 1998 will be trued-up upon completion of reasonableness review of the capital additions for 1996 and 1997. The majority of these costs are uncontested. Parties generally do not dispute capital investments related to net plant in service, but disagree regarding the treatment of certain rate base items and regulatory assets that must be categorized either as sunk costs or as going forward costs.

11.2. Materials and Supplies Inventory

Each utility has included a request for transition cost recovery related to its investment in materials and supplies inventories associated with the generation function, which PG&E, Edison, and SDG&E categorize as an element of sunk costs. Generally, materials and supplies inventories include stores of materials and supplies, such as spare parts at power plant sites and storage facilities. Materials and supplies inventories are a component of rate base, and the utilities earn the authorized rate of return on their net investment in this inventory. As individual inventory parts are used, they are either expensed or capitalized and depreciated, depending on the particular use and dollar amount involved, and the utility recovers its investment.

The utilities request the following amounts as of January 1, 1998:

PG&E	$13.947 million
Edison	$39.387 million
SDG&E	$10.635 million

11.2.1.The Utilities

PG&E classifies materials inventory by material classes, of which certain classes are specifically related to generation and which PG&E has assigned to fossil power plants. Hydroelectric materials were assigned to watersheds based on inventory location, which were mapped to FERC licenses. In A.96-08-001, PG&E requested transition cost recovery of $14.214 million as of December 31, 1995. In A.96-08-072, PG&E requested transition cost recovery of $13.947 million as of January 1, 1998. As stated in Exhibit 35, the end-of-year 1995 and even the forecast January 1, 1998 materials and supplies inventory balances are not relevant, because the amount that PG&E will seek to recover as transition costs is the above-market costs associated with materials and supplies inventory for a given plant at the time of its market valuation. In other words, PG&E proposes that the market valuation process determine both the level and value of above-market materials and supplies inventory, if any. PG&E states that such above-market costs are uneconomic by definition and therefore eligible for transition cost recovery.

Edison explains that materials and supplies inventories are maintained for operation and maintenance of the company. Included in Edison's request are a combination of materials and supplies inventories that can be specifically identified with non-nuclear generating units and a portion of those inventories not specifically assigned, but supporting all of Edison's functions. Materials and supplies inventories may be stored at individual plant sites or at central locations. Edison requested transition cost recovery of $39.387 million as of December 31, 1995 and has not estimated any change in its request for transition cost recovery as of January 1, 1998.[18]

Edison agrees that any difference between the net book value and market value should be recoverable through the CTC as a generation-related asset. Edison proposes that recovery of the net above-market costs of materials and supplies inventories should be reflected in the market value on the date of divestiture or other market valuation. Edison therefore agrees that recorded amounts as of December 31, 1995 and estimates as of January 1, 1998 are irrelevant for these purposes, as are the audit findings. Edison contends that because shareholders fund the initial investment in materials and supplies inventories, these costs are no different than any other generation-related costs addressed in § 367. Edison emphasizes that once market valuation occurs, replenishment of materials and supplies inventories is a going forward cost, i.e., a component of operation and maintenance costs as addressed in AB 1890.

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[18] Exhibit 115 clarifies that in its February, 1997 update to A.96-08-071, Edison revised its request for transition cost recovery for materials and supplies inventories by approximately $1 million, to $40.349 million. However, excluding 1996 and 1997 capital additions and related items, the January 1, 1998 amount requested is $39.387 million.

SDG&E states that the materials and supplies inventory balances address the cost of materials and supplies currently in inventory, purchased for use in the generation business for construction, operation, and maintenance purposes. SDG&E requests recovery of materials and supplies inventories as recorded on December 31, 1995 of $10.635 million. SDG&E has not changed its request for recovery as of January 1, 1998, and explains that this amount will be updated to reflect the recorded balance as of December 31, 1997. Contrary to PG&E's and Edison's proposals, SDG&E recommends that amortization of the December 31, 1997 recorded book balance of materials and supplies inventories should be completed by way of the 48-month straight line amortization described in D.97-06-060, beginning January 1, 1998. Whether materials and supplies inventories are uneconomic or not should be addressed in the market valuation process, with an appropriate true-up to the transition cost balancing account. SDG&E believes that materials and supplies inventories will be accounted for as part of the market valuation process, but likely not as separate items. In addition, SDG&E believes that the likely market value of these inventories is closer to zero than to the net book value, because each of these components is relatively unique and not readily available. SDG&E does not oppose the auditors' recommendation to use the verified December 31, 1997 balances as a starting point for transition cost recovery and amortization, beginning January 1, 1998.

11.2.2. Audit Report Recommendations

As stated in Exhibits 45, 46, and 47, the auditors found that a qualified opinion was necessary for the requested transition costs as of December 31, 1995, for PG&E, Edison, and SDG&E, because the auditors were necessarily unable to observe the physical inventories of that date. The auditors question the costs as of January 1, 1998 because of the qualification as of December 31, 1995. The auditors were unable to satisfy themselves as to the viability and realizability of these balances through alternative auditing procedures; however, the auditors also state that they are not aware of anything that would cause them to believe that these amounts are materially misstated. The auditors recommend performing additional verification of the materials and supplies inventories balances prior to their acceptance as transition costs eligible for recovery through the CTC. The auditors believe that since § 367 provides for the recovery of generation-related assets that were in rates as of December 20, 1995, the verified uneconomic costs of materials and supplies inventories are eligible for transition cost recovery.

11.2.3.Intervenors

ORA recommends postponing the decision on eligibility of materials and supplies inventories pending divestiture. While ORA is inclined to recommend excluding these inventories from transition cost recovery as going forward costs, it recognizes the possibly uneven treatment inherent in divestiture.

TURN recommends not allowing recovery of materials and supplies inventories not be allowed through the transition cost balancing account. By allowing recovery of the inventory balances as of December 31, 1997 (i.e., ensuring that these amounts are amortized over the transition period, even if trued up for market valuation), TURN believes, the Commission would require ratepayers to pay for assets which are being expensed or capitalized when used and then allow the utilities to replenish these inventories at ratepayer expense with no review. TURN believes that inventory book and market values will be close to identical. Furthermore, TURN contends that decisions to replenish inventories made after January 1, 1998 are going forward costs. If transition cost recovery is allowed, market valuation should be required on January 1, 1998. Any unamortized uneconomic costs should receive the reduced rate of return the Preferred Policy Decision adopted for generation assets eligible for transition cost recovery. Alternatively, TURN proposes that the verified December 31, 1997 unamortized balance should receive the authorized rate of return, with subtractions to that balance as components are used, or as plants are sold with their inventories, with no additions for replenishment or amortization of unused balances.

FEA recommends that materials and supplies inventories are going forward costs and therefore, should not be recoverable as transition costs. To allow such recovery for the January 1, 1998 balances for the investor-owned utilities raises competitive advantage concerns, because competing generators must recover these costs through the market. FEA states that § 367 provides for the recovery of the uneconomic costs of all generation-related assets that were in Commission-approved rates; therefore, materials and supplies inventories represent a cost category that is eligible for transition cost recovery. FEA further states that while the cost category may be eligible for transition cost recovery, it is premature to allow recovery. FEA doubts that sunk inventory costs are uneconomic, since it anticipates that when market valuation occurs, the market value will equal the net book value of these assets. FEA agrees with the auditors' recommendation to exclude that the December 31, 1997 balances from transition cost recovery until they are verified.

FEA also questions Edison's estimates of materials and supplies inventories as of December 31, 1995, asserting that this balance represents a 170% increase from 1994, and recommends that the Commission require Edison to explain and justify this large increase.

CIU recommends that the non-fossil plants' materials and supplies inventory balances be verified and market valued as of December 31, 1997. The uneconomic portions should be recoverable as transition costs. Thereafter, all materials and supplies in inventory that are used must be replenished at each utility's costs and treated as going forward costs, with recovery only from the market.

Because § 367(c) specifically excludes the cost of operating and maintaining the fossil generation units as a going forward cost, EPUC recommends that fossil materials and supplies inventories should not be recovered as transition costs. Because these costs would be the shareholders' responsibility, the proceeds from divestiture or market valuation should also flow to the shareholders. Similarly, EPUC recommends the carrying costs on the unamortized balance of materials and supplies inventory is a going forward cost which must be recovered solely from the market revenues.

11.2.4. Discussion

As of January 1, 1998, the materials and supplies inventories are going forward costs and reflect one component of doing business in the competitive generation market. It is not appropriate to allow the utilities to carry forward existing materials and supplies inventories into the new market, which would confer unnecessary competitive advantages on the utilities and could arguably raise market power concerns. There is no reason that materials and supplies inventories should earn a ratepayer-funded rate of return until market valuation occurs. In D.97-05-088, we determined that there was substantial potential for double recovery for materials and supplies inventories related to Diablo Canyon. Our concerns have not been allayed. As materials and supplies inventories are consumed, such components are either expensed or become part of capital expenditures. We prefer not to establish complicated tracking mechanisms to distinguish between materials and supplies inventories and capital expenditures.

All parties agree that materials and supplies inventories should be accounted for as part of the market valuation process; the question is when that valuation should occur. PG&E agrees that replenishment of materials and supplies inventories after January 1, 1998 is a going forward cost. Edison states that replenishment of materials and supplies after market valuation is a going forward cost. The fact that Edison and PG&E have proposed to divest such inventories along with associated plant is reasonable and fulfills our intent to ensure that the highest possible market valuation can be obtained. To the extent that such components will be divested with the associated plant, the auction price should account for this. In general, we expect that market and book value should be very close, although it may be difficult to distinguish the overall bid into various components.

We will not defer our decision on eligibility as ORA suggests. If divestiture is not completed by December 31, 1997, which we recognize is likely, we find that the materials and supplies inventories should be market valued as of December 31, 1997, or as close to that date as possible, i.e., a physical inventory shall be undertaken with an assessment of the fair market value of the inventory components.

Appraising the materials and supplies inventories as of December 31, 1997, to the extent these components are not yet divested, is reasonable because we expect that market and book value should be reasonably close and that an uneconomic component is unlikely. However, we will allow the difference between market and book costs for materials and supplies inventories to either be debited or credited to the transition cost balancing account. This approach allows market valuation procedures for divestiture and transition cost recovery to be cohesive. It is a far different and simpler undertaking to appraise the market value of various pieces of equipment, than to appraise a power plant. The utilities should report the market value of the materials and supplies inventories in the appraisal applications, due on March 2, 1998, which is subject to scrutiny by parties and this Commission. As of January 1, 1998, materials and supplies inventories for fossil plant assets are going forward costs, which should be excluded from transition cost recovery, consistent with the intent of AB 1890.

Alternatively, the utilities may deem the book value of the December 31, 1997 materials and supplies balances to equal their market value. In this case, the utilities should track the difference between the physical inventories existing as of December 31, 1997 and the physical inventories existing as of the date of actual market valuation. Changes in inventory levels are going forward costs and are not eligible for transition cost recovery.

11.3. Fuel Inventories and Fuel Oil Inventories

Fuel oil inventories are maintained in tanks at each power plant site, as a back-up fuel source in the event that natural gas becomes unavailable. Each of the utilities seeks transition cost treatment of fuel oil inventories, as either sunk costs or as generation-related assets which were being collected in Commission-approved rates as on December 20, 1995. In addition, Edison maintains fuel gas inventories, associated with specific units, as needed for winter reliability, load balancing, and to provide portfolio flexibility. Edison also maintains coal supplies at the Mohave and Four Corners generating stations as active working inventories and emergency on-site inventories to maintain system reliability.

The utilities estimate the following amounts to be eligible for recovery as of January 1, 1998:

PG&E	\$28.9 million: fuel oil inventory
Edison	\$68.8 million: fuel oil inventory
	\$34.7 million: gas inventories
	\$9.6 million: coal inventories
SDG&E	\$13.3 million: fuel oil inventory

11.3.1.The Utilities

PG&E requests \$40.734 million to be recovered as transition costs as of December 31, 1995 and forecasts \$28.493 million to be eligible for recovery as of January 1, 1998. PG&E recommends recovering only the uneconomic portion of the fuel oil inventory balances, as determined at the time of market valuation. PG&E believes its forecast of fuel oil inventories is reasonable, as it has been reviewed by the Commission in D.96-12-080, which adopted a December 31, 1997 forecast of fuel oil inventory. PG&E believes it would be imprudent to burn these inventories down to zero or to sell them for other uses, although PG&E recognizes that it is likely to burn some of its current inventory. Furthermore, PG&E contends that it is the actual balances recorded during the transition period which will be used to determine the amount to be recovered as transition costs. PG&E recommends verifying the actual balances as part of the market valuation process.

Edison requests transition cost recovery related to fuel inventories of \$113 million as of December 31, 1995 and January 1, 1998. Of this amount, \$68.8 million is for fuel oil, \$34.7 million is for gas inventories, and \$9.6 million is for coal inventories. Edison recommends postponing that any decision on the disposition of fuel oil inventory for at least 18 months, to enable the Commission or the ISO to conduct a study on the need for continued back-up fuel oil inventory. In the interim, Edison proposes to retain ownership of the fuel oil inventory and make such inventory available for sale at book value to new plant owners on an as-needed basis. Edison contends that the uneconomic portion of gas and coal inventories should be recoverable through the transition cost balancing account on the date of market valuation. Furthermore, Edison has stated that as of January 1, 1998, carrying costs on fuel inventories are going forward costs and therefore it is not proposing to recover these through transition cost treatment.

SDG&E requests that $13.321 million be found eligible for transition cost recovery related to fuel oil inventories, as of December 31, 1995 and December 31, 1997, and states that this amount will be updated to reflect actual numbers recorded as of December 31, 1997. SDG&E agrees that the economic or uneconomic determination of these assets should be made as part of the market valuation process. Pursuant to the current ratemaking process, SDG&E recommends no amortization of these assets as sunk costs, but rather that the recorded monthly balances earn the 3-month commercial paper rate as carrying costs.

11.3.2. Audit Report Recommendations

Similar to its recommendations for materials and supplies inventories, the auditors have issued a qualified opinion for PG&E, Edison, and SDG&E as of December 31, 1995, because they agree with the estimates in theory, but obviously could not participate in a physical inventory count and assessment of realizability. Again, nothing came to the auditors' attention that would cause them to believe that these estimates are materially misstated. The auditors recommend making a physical count and assessment of realizability be made at year-end 1997 to verify actual amounts. The auditors believe that since § 367 provides for the recovery of generation-related assets that were in rates as of December 20, 1995, the verified uneconomic costs of fuel inventories and fuel oil inventories are eligible for transition cost recovery.

11.3.3. Intervenors

ORA supports PG&E's proposal to determine both the book and market value of its fuel oil inventories at the time of divestiture. ORA also supports SDG&E's proposal to record the carrying charges associated with current inventory levels at the 3-month commercial paper rate until the plant undergoes market valuation, rather than amortizing its fuel oil inventory balances over the 48-month transition period. ORA recommends that unless needed for reliability purposes, which will be confirmed by the ISO, fuel inventory levels should be verified by physical observation at the same time these assets are market valued, and that the difference between market value and book value be included in the transition cost balancing account. ORA has clarified its position that carrying charges will be allowed for 1998 only, which will allow the ISO time to make this assessment.

ORA recommends allowing Edison's requested recovery for gas and coal inventories, based on a market valuation of these inventories as of December 31, 1997, which ORA claims will be relatively simple compared to market valuing power plants, at least for gas inventories. Replenishment of inventory levels after January 1, 1998 would not be eligible for transition cost recovery. ORA declares that deferring market valuation of these inventories until the associated plant is either market valued or sold would allow changes in inventory levels after January 1, 1998 to receive transition cost treatment. ORA contends that for gas inventories, unit prices are available and easily determined on the open market.

While admitting that valuing the coal inventory is more complex, because there is no easily determined market price, ORA disagrees that its market value is zero just because of the difficulty of transporting it to another site. ORA agrees with TURN's overall policy principle that if a plant is economic, none of its components should be found uneconomic on a piecemeal basis. Therefore, only if the coal plants are found uneconomic in comparison with the Power Exchange, and ultimately, upon market valuation, could the coal inventory be found uneconomic. ORA asserts that the value of this inventory will be reflected in its fair market value; i.e., if inventory is larger, the new owner should be willing to pay more since acquisition of the inventory reduces future fuel costs. Thus, the regulatory appraisal proposed by ORA should reflect an arms-length transaction, rather than what might occur if the coal cannot be moved.

TURN states that fuel oil inventory recovery is an exception to its proposal that all costs associated with fuel inventories should be excluded from transition cost eligibility. TURN agrees that, for 1998 only, the decision on recovery of fuel oil inventories should be deferred and that the utilities should be allowed recovery of carrying costs in the transition cost balancing account at the commercial paper rate, pending an ISO decision on the need for fuel oil inventory. TURN further recommends that gas inventories and coal inventories should not be eligible for transition cost recovery, because market and book values should be very close, and because replenishment of inventories after January 1, 1998 is a going forward costs. Alternatively, TURN recommends that if eligibility is allowed, these assets should be market valued on January 1, 1998, subject to a review of prudence, with the commercial paper rate applied to any difference between market and book values which is booked to the transition cost balancing account. This is the current approach under the Energy Cost Adjustment Clause (ECAC).

FEA maintains that fuel inventories should not be allowed transition cost recovery until the Commission is satisfied that the December 31, 1997 balances are reasonable, are uneconomic, are not going forward costs and that allowing recovery of these costs would not confer a competitive advantage on the utilities. In general, FEA asserts that such costs are going forward costs and recovery would therefore violate the standard of competitive neutrality.

CIU recommends excluding fuel and fuel oil inventories from transition cost recovery as of January 1, 1998, because these costs are not part of fossil capital investment, therefore, these costs are going forward costs. In Exhibit 100, CIU's witness Barkovich testifies that the "most important consideration seems to be whether these fuel oil inventories are part of the 'fossil capital investment,' and thus a sunk cost to be recovered or whether they are 'fuel and fuel transportation costs.'" CIU believes that these inventories are related to fuel and fuel transportation costs and are excluded from recovery by § 367(c) as going forward costs. CIU asserts that if § 367(c)(2) is found to apply to Edison's future fuel oil costs, Edison may be allowed to recover such costs.

EPUC states that § 367(c) specifically excludes the cost of fuel and fuel transportation for fossil generation from transition cost eligibility. Therefore, EPUC recommends that fuel inventories are not permitted to be recovered through the transition cost balancing account, nor are carrying costs recoverable. Because fuel inventories are the sole responsibility of the utilities' shareholders, the gain on any sale at divestiture or market valuation should flow to the shareholders. Enron agrees with CIU's and EPUC's assessment of this issue.

11.3.4. Discussion

It is appropriate to defer consideration of the transition cost recovery of fuel oil inventory pending the determination of the ISO as to whether those inventories are needed for system reliability. However, we are not convinced that this is an issue which FERC is considering. Fuel oil inventory issues may remain in this Commission's jurisdiction. The utilities should indicate with specificity the forum in which they expect these issues to be considered and the timing of this consideration. The utilities should include this information in the March 1998 appraisal application. We will defer ruling on the eligibility of transition cost recovery for fuel oil inventories for 1998. The utilities may apply the 3-month commercial paper rate to the unamortized balance of the fuel oil inventory level.

D.94-10-044 adopted a sharing mechanism for Edison's fuel oil pipelines and authorized Edison to enter into third-party contracts to transport fuel oil over its pipeline systems, provided this use did not interfere with the system's back-up capability. (56 CPUC2D, 642, 648.) This sharing mechanism allocated 87.5% of gross revenues to shareholders and 12.5% to ratepayers. We do not have the record to determine how this sharing mechanism interacts with the fuel oil inventory levels maintained by Edison. We direct Edison to file a proposal for the treatment of fuel oil inventory which is consistent with the guidelines established on this decision and which ensures that ratepayers continue to benefit from the gross revenue mechanism. Edison shall include this proposal in its appraisal application, to be filed on March 2, 1998.

For gas and coal inventories, it is reasonable to market value these components as of December 31, 1997 or as close to that date as possible. To the extent that divestiture occurs prior to year-end 1997, we will have that information. Again, we wish to establish a bright line for determining uneconomic costs up to January 1, 1998 and going forward costs after that date. Deferring market valuation of these inventories until the associated plant is either market valued or sold would allow changes in inventory levels after January 1, 1998 to receive transition cost treatment.

If divestiture is not complete, and for those assets retained by the utility, it will be relatively simple to compare the market price of gas with the book value of Edison's gas inventory. While coal may be more difficult, the value of the coal inventory is not based on transporting it to a different power plant, but on its intrinsic market value. Once the applications initiating market valuation by appraisal are filed, we will direct the Energy Division to hold a technical workshop devoted to these very specific appraisal issues for coal in advance of the generic issues of market valuing plants retained by the utilities. In this way, we can establish a bright line between inventory costs eligible for transition cost recovery and those that will be classified as going forward costs as of January 1, 1998. Replenishment of inventory levels after January 1, 1998 will not be eligible for transition cost recovery. Carrying costs should not be allowed on any unamortized difference between market and book value. Because the transition cost balancing account itself will be subject to the commercial paper rate of interest, there is no need to apply an additional interest rate calculation. In the alternative, Edison may deem the book value of the December 31, 1997 gas and coal inventories balances to equal their market value. In this case, Edison should track the difference between the physical inventories existing as of December 31, 1997 and the physical inventories existing as of the date of actual market valuation. Changes in inventory levels are going forward costs and are not eligible for transition cost recovery.

11.4. Non-nuclear Decommissioning

Non-nuclear decommissioning refers to the obligation to remove a major utility facility, usually a power plant. Under traditional cost-of service regulation, it is the utility's obligation to remove retired plant and to mitigate environmental and other effects associated with that retired plant. Decommissioning costs are estimated as a specific dollar amount of the costs involved in dismantling the facility and are amortized through the annual depreciation accrual. In other words, non-nuclear decommissioning costs are a component of each utility's depreciation expense, based on each utility's most recent general rate case (GRC). PG&E, Edison, and SDG&E contend that since generation facilities were constructed to serve ratepayers, who would then receive the benefits of these facilities over their useful lives, these costs should be recoverable as eligible transition costs. The intervenors do not dispute the eligibility of this category, but question how the costs are calculated and what amount, if any, should be included in the transition cost balancing account for amortization beginning January 1, 1998, as opposed to the amount that should be determined through market valuation.

The utilities estimate the following amounts as of January 1, 1998:

> PG&E: $596.168 million (net nominal amount, to 1/1/98 to determine that amount amortized through transition cost balancing account)
>
> Edison: $365.266 million
>
> SDG&E: $ 70.749 million

PG&E has no estimates of decommissioning costs for its hydroelectric facilities, but estimates negative net salvage amounts for these facilities of $273.6 million.

11.4.1. Utilities

PG&E believes it will retain the environmental liability for generating plant, whether plant is divested, retained, or retired, and that this liability should be recovered as an eligible transition cost. As of January 1, 1998, PG&E proposes to begin to recover decommissioning cost estimates based on its most recent GRC-authorized amounts. At the time of market valuation or retirement, PG&E recommends truing-up the transition cost balancing account to reflect any revised amounts.

PG&E also anticipates that it will retain the non-environmental liability for retired plant, which it proposes to recover through the transition cost balancing account, but predicts that it is likely that the non-environmental decommissioning obligation will be transferred to the buyer upon divestiture of the plant. If plant is retained by the utility, PG&E expects that the appraisal value would consider and reflect these costs. As of January 1, 1998, PG&E proposes to begin to recover decommissioning cost estimates based on the amounts authorized in its most recent GRC. As the time of market valuation or retirement, PG&E proposes to true-up the transition cost balancing account to reflect any revised amounts.

Edison thinks that non-nuclear decommissioning, including any environmental requirements, should be the responsibility of the owner of the generating station. The estimated costs should be determined at the time of market valuation, whether by appraisal or divestiture. Edison maintains that this position is supported by ORA, TURN, and CIU. Edison agrees with ORA's proposal to continue to recover decommissioning costs at the level currently included in authorized rates.

Assuming that decommissioning costs will be determined through the market valuation process, Edison proposes to continue the accounting for accumulated decommissioning amortization as an offset to rate base. This is in contrast to PG&E's proposal to remove the decommissioning reserve from rate base, which Edison asserts would require determining the present value of the pre-2001 obligations and applying interest calculations on the unpaid decommissioning funds.

Edison contends that because D.97-08-056 precludes the utilities from recovering the costs of environmental remediation at its fossil sites through the Hazardous Waste Mechanism, Edison must seek recovery of these costs through either the Environmental Compliance regulatory asset or through environmental decommissioning. Edison explains that environmental remediation generally cannot be performed until final decommissioning, so it agrees with PG&E that it is necessary to estimate this obligation. Edison agrees with ORA's recommendation to base these costs on actual work performed for divested plants and on costs estimated through soil studies for plants not divested, with the caveat that such work must occur prior to 2001. Otherwise, Edison claims that all environmental remediation costs would need to be based on soil studies, rather than actual costs, and included in the four-year transition period.

SDG&E recommends amortizing the forecasted decommissioning expense (for both environmental and non-environmental decommissioning) ratably over the transition period. The economic or uneconomic treatment should be determined in the market valuation process, with the transition cost balancing account trued-up appropriately. SDG&E states that the ORA and TURN proposal to continue the current depreciation expense levels to include decommissioning until market valuation occurs and to allow CTC recovery for environmental costs is an acceptable alternative.

11.4.2. Audit Report Recommendations

The auditors explain that PG&E was authorized to collect fossil decommissioning costs in its 1996 GRC decision (D.95-12-055). The company was allowed to collect decommissioning funds based on estimated decommissioning costs, with the expectation that actual costs would be trued-up with collections at the time of actual decommissioning. The auditors questioned PG&E's estimates of decommissioning costs, because PG&E escalated the estimate for each plant to nominal (or current) dollars as of the expected date of decommissioning or 2001, whichever is sooner, using the same Consumer Price Index (CPI) inflator factors used to escalate decommissioning costs to the 1996 test year in the 1996 GRC. This escalated cost was then discounted to January 1, 1998 net present value amounts using a discount rate of 7.17% (the reduced return on transition cost assets for PG&E, as discussed in Section 18). In D.95-12-055, we specifically denied PG&E's request to base decommissioning costs on nominal dollars and instead required that costs be based on constant 1996 dollars. The auditors believe that the net present value calculation is acceptable for these purposes. The auditors also recommend reviewing contingencies and labor overheads, since there may not be a true-up to actual costs in the transtion cost recovery process for plants that are decommissioned after the transition period.

Negative net salvage results when the cost of removing a facility exceeds the amount that is expected to be received from the sale or other disposition of the retired unit. Salvage and removal costs reflect actual amounts recorded at the time of the retirement, and retirement costs reflect original cost. Depreciation reserves are trued-up for revised net salvage estimates and adjusted for revised remaining lives based on updated depreciation studies. PG&E relied on published depreciation statistics for other utilities to determine net salvage percentages with respect to retirement of its hydroelectric facilities, because it did not have sufficient data to develop its own statistics. The auditors determined that these amounts were estimated correctly and that the negative net salvage amount is appropriate to include in PG&E's estimate of transition costs. The auditors note that because net salvage factors are embedded in depreciation rates, it is difficult to identify the amount of net salvage included in the reserve for depreciation at any one time. The auditors explain that this is not necessary because the proper approach is to assume that classes of plant assets will be fully depreciated before salvage factors produce additional accruals. The auditors recommend recovering this cost through market valuation rather than as a charge to the transition cost balancing account. PG&E agrees with this recommendation and states that this cost category will not be recovered as a separate item in the transition cost balancing account, but will be factored into the market valuation of PG&E's hydroelectric facilities as part of the depreciation reserve. FEA agrees and recommends that we carefully review these amounts.

The auditors explain that Edison recovers fossil decommissioning costs in its depreciation rates and the collected decommissioning costs are included in the depreciation reserve balance (which is an offset to rate base). The auditors have not questioned decommissioning costs for Edison, because Edison explains that the future owners of these plants will assume the decommissioning obligation. Edison explains that any amounts collected through depreciation or future net salvage will be deducted from the unamortized investment upon market valuation. The auditors have not questioned any of SDG&E's decommissioning costs.

11.4.3. Intervenors

On a policy level, ORA asserts that decommissioning expenses for fossil plants do not create the same kind of public safety concerns posed by nuclear decommissioning, which costs are to be recovered through a separate nonbypassable rate. ORA contends that non-nuclear decommissioning is not a past investment by shareholders, but a future obligation of the utilities. ORA recommends that non-nuclear decommissioning costs should not be estimated at this time. ORA agrees that environmental decommissioning costs should be directly recoverable through the transition cost balancing account, based on actual work performed for divested plants and based on soil studies for plants which are not divested. For non-environmental decommissioning, ORA recommends that for divested assets or assets retained but not retired during the transition period, any unfunded non-environmental decommissioning costs at the time of market valuation should be reflected through the market price of the asset.

Prior to market valuation, amortization of the non-environmental decommissioning costs should be permitted at the most recent GRC-authorized level over the 48-month amortization period, on a straight-line basis, according to ORA. Upon market valuation, future decommissioning obligations would be transferred either to the new owners or to shareholders, and further transition cost recovery for these costs would cease. This approach reflects ORA's preference for market mechanisms and eliminates the need for separate accounting for decommissioning costs. In addition, ORA maintains that separate recovery of unfunded decommissioning expenses through the transition cost balancing account would be anticompetitive. Non-environmental decommissioning costs of assets retired during the transition period should be recoverable through the transition cost balancing account.

TURN agrees that the utility retains the environmental liability whether the plant is divested, retained, or retired and should recover this cost through the transition cost balancing account. The timing of environmental decommissioning should be accounted for in a net present value calculation to the extent it occurs after 2002. TURN also recommends that the utility should retain the non-environmental decommissioning obligation of retired plants.

TURN believes that the non-environmental decommissioning obligation should transfer to the buyer if the plant is sold. If the plant is retained, the appraisal price will account for and reflect these costs. Again, TURN recommends that the appraisal take into account the timing of decommissioning after 2001 through a net present value calculation.

For both environmental and non-environmental decommissioning, to the extent any decommissioning costs are recovered prior to being spent, these costs should be accounted for as a rate base offset. As of January 1, 1998, TURN recommends that the most recent GRC-authorized amounts should be included as a current transition cost (i.e., amortized over the 48-month transition period). These costs should then be trued-up as plants are divested and decommissioning obligations become clearer.

FEA has not distinguished between environmental and non-environmental non-nuclear decommissioning. FEA recommends that decommissioning should be stated in present value amounts, not nominal dollar amounts, and is concerned that contingency funds may be collected for contingencies which will not arise. FEA agrees with the auditors that PG&E's negative net salvage for hydroelectric facilities should not be eligible for transition cost recovery, but rather should be reflected in the market valuation process.

CIU agrees with Edison's proposal and finds it preferable and more accurate to use the market mechanism of divestiture or other market valuation to transfer this responsibility either to a new owner or to utility shareholders through the appraisal process. The amount of decommissioning to be recovered should be determined in conjunction with the market valuation of all non-nuclear generation. CIU recommends that estimates should be avoided if possible and that contingencies should be excluded.

EPUC agrees with Edison's proposal to include both the environmental and non-environmental decommissioning obligation in the transition cost balancing account through the market valuation of the generating plants, which shifts the responsibility for decommissioning to the future owner. EPUC recommends that accumulated decommissioning amortization should continue as an offset to rate base.

11.4.4. Discussion

It is important to distinguish between the recovery of generation-related environmental decommissioning costs and costs recovered in the Hazardous Substance Mechanism (HSM). The HSM recovers costs that are not already recovered in rates, whereas environmental decommissioning is recovered in current rates through the decommissioning expense. (RT: 918, 2974.) D.97-08-056 prohibits the utilities from entering any costs associated with generation into their HSM accounts. (D.97-08-056, mimeo. at 10.)

We are persuaded by PG&E's argument that, in accordance with state and federal law, the utilities remain liable for contamination on power plant property. Because it is not probable that the environmental decommissioning responsibility can be transferred to new owners, we will allow the uncovered portion of the costs in rates to be amortized as a current cost in the transition cost balancing account. Amortization of these costs are eligible for acceleration. We will treat these costs as a current rate base offset, as they are accumulated prior to being spent. The timing of environmental decommissioning costs after 2001 should be accounted for in a net present value calculation.

To the extent that the environmental non-nuclear decommissioning can be transferred to new owners and is reflected in the purchase price, we will require appropriate true-ups and credits to the transition cost balancing account. In addition, the utilities are required to true-up the transition cost balancing account according to updated studies and actual costs incurred. Assuming plants are retired before the end of the transition period, a study should be completed of the costs of decommissioning and appropriate true-ups should be made to the transition cost balancing account for costs of actual decommissioning work (both environmental and nonenvironmental) and revised decommissioning studies. A review of this methodology will occur in the annual transition cost proceeding.

Consistent with our preference to use market mechanisms when possible, we concur that the market valuation process for both divested and retained plants will yield more accurate and useful values of non-nuclear non-environmental decommissioning costs than will an estimate of what these expenditures are likely to be. We will adopt Edison's recommendation that non-nuclear non-environmental decommissioning should be the responsibility of the owner of the generating station. We will not estimate these costs now, but will determine them at the time of market valuation, whether by appraisal or divestiture.

Both environmental and non-environmental non-nuclear decommissioning costs should continue to be recovered at the level currently included in authorized rates and amortized beginning January 1, 1998. As both Edison and TURN recommend, the accumulated decommissioning amortization should be accounted for as an offset to rate base. There is no need for accelerated depreciation of the non-nuclear decommissioning expense, because the non-environmental amounts will be reflected in the market valuation process. We agree with ORA that any unfunded amounts are going forward costs and as such, should not be included in the transition cost balancing account. Accelerating the depreciation of these costs would merely blur this bright-line test.

We cannot predict when these costs will be incurred, but we are convinced that it does not make sense to treat all of these costs as if they will be incurred by 2001. We will allow recovery of non-nuclear decommissioning costs in the transition cost balancing account to the extent they are allowed in current rates. This is a reasonable approach which allows some of these costs to be collected prior to market valuation, but will then adjust for market valuation. As we have previously declared, it is important that market valuation occur sooner rather than later. Divestiture is proceeding; we are initiating appraisal of retained assets in early 1998. There should certainly be additional information available to make these adjustments well before 2001. Costs recovered in rates should continue to be treated as a rate base offset.

We concur with the approach to hydroelectric negative net salvage recommended by the auditors and agreed to by PG&E: the $273.6 million estimated in this cost category will not be recovered as a separate item in the transition cost balancing account, but will be factored into the market valuation of PG&E's hydroelectric facilities as part of the depreciation reserve.

11.5. Construction Work In Progress and Retirement Work In Progress

The Construction Work In Progress (CWIP) account includes costs for projects that were under construction as of December 31, 1995. Under traditional ratemaking, CWIP costs are either charged to future plant additions or to abandoned plant accounts. Future plant additions will be evaluated for reasonableness in the appropriate capital additions proceeding using the requirements delineated in § 367 and specified in D.97-09-048. CWIP costs include, for example, costs for plant additions, major equipment modifications, hydroelectric plant relicensing, and replacement of equipment. For purposes of market valuation, PG&E and Edison recommend that CWIP be considered a sunk cost which will be reflected in the net book value of the plant at the time of divestiture or other market valuation. The utilities also presented CWIP balances for 1996 and 1997, which represent projects for which construction is not yet complete and costs are not yet transferred to plant in service. These balances will be addressed in the appropriate capital additions proceeding. Parties generally agree that CWIP balances should be recovered as capital additions when the projects are transferred to plant in service and not separately.

Retirement Work in Progress (RWIP) are the costs involved with retirement of plant assets, such as the cost of removal and salvage. While CWIP is not part of rate base, RWIP is accounted for as part of the accumulated depreciation reserve; i.e., accumulated depreciation reserve is an offset to rate base and RWIP decreases that reserve. Edison recommends that RWIP should not be excluded from transition cost recovery, because RWIP is not associated with CWIP, nor will these costs be dealt with in the capital additions proceeding.

11.5.1. Utilities

PG&E presented a balance of $35.3 million in CWIP as of December 31, 1995. In general, PG&E recommends recovering CWIP balances in capital additions when those projects are transferred to plant in service. However, PG&E recommends recovering CWIP balances for projects started prior to December 31, 1995 in the transition cost balancing account, if the corresponding capital additions are not approved. PG&E contends that costs that are not eligible for capital addition treatment, but were incurred prior to the effective date of AB 1890 and were approved in the GRC should be eligible for transition cost recovery as abandoned projects. PG&E also recommends that CWIP be considered a sunk cost in the market valuation process; e.g., for divested plants, CWIP would be transferred to the new owners and reflected in the net book value of that plant. The audit report did not question costs related to the December 31, 1995 balance, but did question certain costs included as CWIP as of January 1, 1998.

Edison has a balance of $74.3 million in CWIP as of December 31, 1995. Edison states that CWIP recovery has not been proposed in this proceeding, with the understanding that CWIP assets identified on December 20, 1995 which close to capital additions between 1996 and 2001 will be reviewed and recovered as capital additions in future years. However, Edison states that any CWIP existing as of December 31, 1995 should be eligible for recovery through the transition cost balancing account, if it is not recovered as a capital addition. Edison agrees that CWIP should be included in the market valuation process, i.e., to the extent there is any CWIP remaining on the date a generation plant is sold to a new owner, it should be reflected in both the book and market values of that station. Edison recommends including RWIP as part of the depreciation reserve and states that ORA now agrees with this treatment. The audit report questions two projects which the auditors believe were improperly included in Edison's CWIP balance as of December 31, 1995, the total of which is $3.5 million.

SDG&E presents a CWIP balance of $20.2 million as of December 31, 1995 and a RWIP balance of $290,000. SDG&E recommends considering CWIP issues in the capital additions proceeding; however, CWIP amounts booked prior to December 20, 1995 should be viewed differently. SDG&E notes that some CWIP will become abandoned plant and will be addressed in the capital additions proceeding. SDG&E maintains that it is premature to adopt TURN's recommendation to exclude CWIP from transition cost recovery.

The audit report notes that SDG&E ceased construction and reversed charges totaling $143,000 which SDG&E expects will not be eligible for transition cost treatment under the requirements of AB 1890. The auditors concur with this treatment.

11.5.2. Intervenors

ORA recommends that CWIP balances should only receive transition cost treatment when the related capital addition is approved and moved to a plant account. ORA shares TURN's concerns regarding the potential for double recovery. If the related capital addition is not approved, the associated CWIP should not be recoverable through the transition cost balancing account. However, ORA also recommends that specific projects which were reasonable when initiated, but which do not meet the criteria established in AB 1890, should be reviewed in the appropriate capital additions proceeding. ORA explains that the Commission rarely approves specific projects in GRC decisions, but approves only a forecasted rate base. ORA agrees that abandoned plant treatment for these projects may be appropriate, but, again, suggests that this be determined in the capital additions proceedings. ORA no longer questions transition cost treatment for RWIP accounts for Edison.

TURN recommends that CWIP be ineligible for transition cost recovery, because of the potential for double counting. TURN recommends recovering that CWIP balances in capital additions when projects are transferred to plant in service. If CWIP balances are not deemed eligible for transition cost recovery through capital additions, these balances should be addressed on a case-by-case basis. TURN advocates that CWIP investments imprudently incurred should not be recovered at all and that expenditures incurred in 1996 and 1997 are of particular concern, given that such investments may have been undertaken to enhance the utilities' competitive positions while continuing to be assured of transition cost recovery. TURN recommends that rather than the effective date of AB 1890 or December 31, 1995 being earmarked as the milestone for decision-making regarding capital investments,the issuance of Rulemaking (R.) 94-04-031/Investigation (I.) 94-04-032 on April 20, 1994 is more appropriate.

FEA recommends addressing CWIP in the capital additions proceeding and contends that the audited CWIP balances as of December 31, 1995 are the appropriate balances to be reflected in CWIP accounts until 1996 and 1997 plant additions are approved.

EPUC recommends recovering CWIP in capital additions when the projects are transferred to plant in service, provided the capital additions have been determined to be eligible pursuant to AB 1890, including those costs incurred prior to December 31, 1995. EPUC states that cost recovery for RWIP is currently reflected in depreciation and amortization accounts in rates approved by the Commission and that these costs should be treated similarly to non-environmental decommissioning costs.

11.5.3. Discussion

If CWIP costs are not allowed in the capital additions proceedings, the utilities, in effect, are requesting to recover these costs as abandoned projects. Parties have briefed the traditional ratemaking approach to abandoned plant. Under cost-of-service ratemaking, the utilities request recovery for abandoned projects in the GRC immediately following abandonment. If recovery is authorized, the utility is allowed to amortize the recorded costs in CWIP, less any accrued Allowance for Funds Used During Construction (AFUDC) over a specified number of years, without any interest. The criteria for abandoned project recovery are delineated in D.83-12-068, as modified by D.84-05-100 and D.89-12-057, and include the following: 1) the project was initiated and completed during a period of unusual uncertainty and dramatic and unanticipated change; 2) the project was found reasonable, both in terms of undertaking and proceeding with the project; and 3) projects were canceled promptly when conditions warranted:

> "The general rule of ratemaking has been that a utility is not allowed to recover the costs of a plant which is not used or useful. But we have created an exception during periods of great uncertainty: 'The exception is the product of the period of dramatic and unanticipated change, initiated most notably for utility planners by the oil embargo of 1973, and extending for almost a decade. The period was characterized

> by great uncertainty in the energy industry, both as to demand growth and availability of supply....During such a period, the ratepayer should participate in the increased risk confronting the utility.
>
> "'But the ratepayer does not become the utility's underwriter in a period of high risk. At all times, the shareholder will bear some of the risks of abandoned projects. The utility should bear a major part of the risk in order to provide proper, management incentives. Also, the ratepayer's participation is limited to those abandoned projects...for which the utility demonstrates to us that it has exercised reasonable managerial skill. We emphasize that the utility bears the burden of proof of reasonableness, not only with respect to the planning and conduct of a given project, but also regarding the cancellation, which must have occurred promptly when conditions warranted. Finally, a perception merely of generalized and ill-defined risk will not suffice to invoke this exception to the 'used and useful' principles. The utility will have to demonstrate that the project which it ultimately abandoned was reasonable throughout the project's duration in light both of the relevant uncertainties that then existed and of the alternatives for meeting the service needs of its customers....' ([quoting from] D.84-05-100, mimeo. pp.3-4)." (D.89-12-057, 34 CPUC 2d 268-269.)

According to PG&E, abandoned project treatment has been typically extended to projects that were no longer economic or necessary. PG&E contends that while these particular projects are economic and necessary, they may not be recoverable due to criteria yet to be identified by the Commission. Further, PG&E contends that restructuring is a period of protracted uncertainty and that because these projects were approved in PG&E's GRC, it would have been imprudent not to continue those projects necessary to maintain generation-related plants. Furthermore, PG&E states that all of these projects were commenced and many were completed before the enactment of AB 1890 and that several were so close to being complete as of December 31, 1995, it would have not been wise to cancel them. PG&E explains that abandoned projects are often canceled in the early phases before physical construction begins.

We do not believe that there was such uncertainty in the electric utility industry due to restructuring as to relieve the utilities of the risk of recovering CWIP costs incurred prior to 1995 which are not found eligible for transition cost recovery in the capital additions proceeding. Indeed, we are concerned that ensuring transition cost recovery for such items could not only lead to double counting, but could confer significant competitive advantages on the incumbents. Therefore, we will exclude transition cost recovery for CWIP for now. Those projects approved in the relevant capital additions proceedings will receive transition cost recovery, because the net book value and associated depreciation amounts are trued-up as a result of those proceedings. Those costs incurred prior to December 31, 1995 which are not approved in the capital additions proceedings do not meet our established criteria for abandoned plant and therefore are not approved for transition cost recovery. To the extent that there is remaining CWIP on the date a generation station is sold, that amount should be reflected in both the book and market values of that station. We will adopt a different treatment for past hydroelectric relicensing costs, as explained in Section 14.

Edison explains that the FERC Uniform System of Accounts requires that when depreciable electric utility plant is retired, the book cost of the retired plant be entered into Account 108, the Accumulated Provision for Depreciation. While the retirement work is in progress, the removal and salvage costs are accounted for in work orders that are also entered into Account 108. If plant is retired before the end of its estimated useful life, traditional ratemaking has provided that shareholders are able to recover their remaining investment in the plant, but not earn any return on the remaining undepreciated plant balance. (D.85-08-046, 18 CPUC 2d 592.) Edison believes that under restructuring, this approach to accounting and ratemaking should not change significantly. As plants are retired with appropriate adjustments to the depreciation reserve and capital additions are added to rate base, the uneconomic portion of the net generation plant will be subject to transition cost recovery.

PG&E adds that under traditional ratemaking for utility plant, assets are depreciated using group depreciation at the asset class or FERC plant account level. Under this approach, assets are depreciated based on average life and when a plant is retired, it is considered to be fully depreciated; i.e. its original cost amount is removed from plant in service and from the accumulated depreciation reserve, with no net change in total book value. Any undepreciated value associated with the asset on retirement is spread to all other assets in a given class or account. PG&E agrees that any remaining net book value will be amortized through the transition cost balancing account over the remaining months of the transition period. For plants that have been retired prior to the beginning of the transition period, there is no impact on transition cost recovery, other than decommissioning funds.

ORA does not propose any changes to traditional ratemaking for retired plant for purposes of transition cost recovery. After market valuation, ORA recommends that ratepayers should no longer be responsible for any additional costs associated with retiring a power plant, including decommissioning.

We agree that RWIP costs should continue to be accounted for as an increase to the accumulated depreciation reserve. As discussed under decommissioning, after market valuation, ratepayers should no longer be responsible for any additional costs associated with retiring a power plant, including decommissioning.

11.6. Common and General Plant

Common plant is defined in the FERC Uniform System of Accounts as those assets associated with more than one utility service, such as electric, gas, and water. (TR: 2454; 18 CFR, Part 101, p. 280, April 1, 1996.) General plant is not defined in the FERC Uniform System of Accounts, but the following accounts are described under the heading of "General Plant:" land and land rights, structures and improvements, office furniture and equipment, transportation equipment, stores equipment, tools, shop and garage equipment, laboratory equipment, power operated equipment, communication equipment, miscellaneous equipment, and other tangible property. Each of these accounts is then characterized as including items not properly included in more specific accounts, in conformance with FERC instructions. (*Ibid*, Accounts 389-399, pp. 329 - 331.) The issue in this proceeding is how to define and treat generation-related common and general plant for PG&E and SDG&E, and general plant for Edison.[11] A certain amount of common and general plant has been allocated to the generation function for each utility in the cost separation proceeding (A.96-12-009 *et al.*) The utilities assert that generation-related common and general plant costs are eligible for transition cost recovery, because they are generation-related costs that were in Commission-approved rates on December 20, 1995 and claim the following estimates as of January 1, 1998:

PG&E:	$80.050 million
Edison:	$42.929 million
SDG&E:	$4.388 million

11.6.1. Utilities

PG&E proposes to recover the uneconomic portion of common and general plant, which the Commission has determined to be generation-related, in the transition cost balancing account, whether such plant is on-site or off-site. PG&E states that it has included only costs associated with common and general plant that had been directly assigned to generation in its accounting records and that this plant is associated with land, buildings, communications, and other equipment located at the generation plants that are immobile and essential to the generation function. PG&E believes this on-site plant should be market valued with the generating plant.

PG&E has not allocated any shared common plant costs, such as those associated with its general office, to generation in this proceeding. PG&E proposes that the amount of shared common plant ultimately determined to be generation-related in the unbundling proceeding should be assigned to generation and therefore be eligible for transition cost recovery, if found to be uneconomic. PG&E asserts that these costs are generation-related that are unavoidable until PG&E's generation has been completely divested. PG&E recommends that off-site assets which

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[11] Because Edison is an electric utility only (other than the small gas and water operations it maintains on Santa Catalina Island), there is no common plant at issue.

are determined to be generation-related in the unbundling proceeding should also be market valued, but this issue should be considered in another phase of this proceeding.

PG&E contends that ORA's position in this proceeding is inconsistent with its position in the unbundling proceeding. In that proceeding, ORA has agreed that both the directly-assigned and indirect allocated costs assigned to generation are appropriate, and furthermore, ORA argued that additional shared common costs should be allocated to generation.

Edison asserts that all generation-related general plant should be eligible for recovery in the transition cost balancing account, which will then be adjusted for market valuation. Edison has no common plant, but provides an analysis of two types of generation-related general plant: 1) site-specific, i.e., which is situated at the generating site and 2) non-site-specific, i.e., assets which are not necessarily physically located at the generating site. Edison contends that both types of assets represent plant invested in specifically to serve the generation function. Edison believes that if the Commission allows recovery only of site-specific general plant in the transition cost balancing account, the remainder of non-site-specific plant should be recovered in non-generation rates. Edison states that site-specific general plant assets were purchased and have been used solely for the operation of generating plant and do not have other uses within the utility; these assets have been included in its divestiture proposals.

Edison disputes ORA's proposal to defer resolving the eligibility of on-site general plant assets until it can be determined which assets will be divested. Edison believes that this violates the Preferred Policy Decision, which orders recovery of up to 100% of the net book value of fossil generation prior to market valuation. Edison further disputes ORA's and TURN's recommendations that no transition cost recovery be allowed for off-site generation-related general plant assets which are either allocated or directly assigned to generation and involve activities that could be reassigned to other utility functions.

SDG&E states that all of its common and general generation-related plant assets are site-specific and should be recovered as generation-related transition costs. SDG&E recommends that the booked amounts should be amortized over the 48-month transition period and that the determination of which portion is uneconomic or economic should be reflected in the market valuation process.

11.6.2. Intervenors

ORA asserts that we must determine whether these assets are directly related to generation, whether the cost is unavoidable, and whether the cost is uneconomic. ORA states that on-site plant which is immobile and essential to the generation function is more directly related to generation than is off-site plant, and that items which are directly assigned to generation are dedicated to the generation function, while items which are indirectly assigned though various allocation methods serve multiple functions. ORA believes that common and general plant assets vary in the degree to which they are unavoidable and recommends that the cost of assets which can be sold, leased, or reassigned to other utility functions is avoidable and therefore not eligible for transition cost recovery. ORA recommends that determining the eligibility of on-site common and general plant should be postponed pending divestiture of the related plants. ORA believes that the off-site common and general plant should not be eligible for transition cost recovery, because the related assets have alternative uses and would be very difficult to market value. Alternatively, ORA recommends that if off-site common and general plant is allowed to be recovered, it should be eligible for inclusion in the transition cost balancing account only if its market value exceeds its book value.

TURN agrees that the uneconomic portion of the on-site common and general plant should be recoverable in the transition cost balancing account and that the on-site assets should be market valued with the related plant generating plant. TURN argues that the off-site common and general plant should not be eligible for transition cost recovery, because these costs are likely to have other uses and are therefore not stranded. TURN recommends that common and general plant which is directly assigned to generation and shared plant which is allocated to generation be deemed ineligible for transition cost recovery. In particular, TURN recommends that shared corporate general plant should not be eligible for transition cost recovery, because these assets are very likely to have alternative uses. TURN also asserts that including off-site common and general plant as eligible for recovery creates perverse incentives influencing the choice between owning and leasing property.

FEA recommends that, unless the utilities can demonstrate that these assets cannot be transferred to other operations or sold at a price equal to or above net book value, these costs should be ineligible for transition cost recovery. FEA asserts that assets, such as vehicles or land, whether on-site or off-site, that may have been used in generation functions in the past may well be usable in the utility's other operations. FEA questions whether such assets are indeed generation-related. FEA contends that divestiture will aid us in our determination of whether an asset claimed by the utility as eligible for transition cost recovery is truly generation-related or not. FEA thus agrees with ORA's proposal that recovery of these assets be deferred until market valuation.

EPUC agrees that the uneconomic portion of the on-site common and general plant should be determined through market valuation and that the uneconomic portion should be eligible for transition cost recovery to the extent it is included in the net book value of capital investment existing as of January 1, 1998. EPUC recommends deferring the market valuation and treatment of off-site common and general plant to Phase 3 or other Commission proceeding, and states that the treatment of these items depends on the proper assignment or allocation of the off-site facilities to various generation plants; e.g., properly allocated off-site common and general plant costs that were part of the net book value may receive transition cost recovery. However, EPUC recommends that if such costs are not part of the net book value, then the costs should be recovered from the Power Exchange or the market.

11.6.3. Discussion

We will distinguish between on-site and off-site common and general plant in our discussion. On-site common and general plant are generation-related assets which appear to be integral to the operation of the corresponding power plants. It would be inconsistent with our efforts to encourage divestiture and to maximize the fair market value of these assets to either not allow recovery of any transition costs associated with these assets or to defer the determination of their eligibility for transition cost recovery. We will allow transition cost recovery via amortization of the on-site common and general plant estimates at the beginning of the transition period and it is our expectation that market valuation will capture the value of such assets. In order to be consistent in our ratemaking approach, the amount of on-site common and general plant assets as of December 31, 1995, which has been verified by the auditors, should be amortized over the transition period. We will true-up the transition cost balancing account once market valuation occurs and will review any assets not acquired by buyers to determine whether they remain eligible for transition cost treatment.

Off-site generation-related common and general plant is more problematic. We will exclude such costs from transition cost recovery at this time, because we expect that the majority of items in this category may well be usable in other unregulated areas of the utilities' or their affiliates or subsidiaries' functions.[20] We agree with ORA that such assets should have many uses; indeed, PG&E has indicated that of its 20,000 accounting records, 19,000 relate to vehicles and another 25 relate to buildings. We believe that there are many opportunities to minimize transition costs in the area of off-site common and general plant. We adopt PG&E's proposal that off-site generation-related common and general plant not be recovered initially in the transition cost balancing account pending efforts by the utilities to mitigate such costs.

To the extent these off-site common and general plant costs cannot be fully mitigated, the uneconomic costs of off-site generation-related common and general plant may be recoverable through transition cost treatment. However, we put the utilities on notice that such mitigation efforts will be thoroughly reviewed and

[20] Such transactions must be undertaken in conformance with our affiliate transaction rules being developed in the affiliate transaction rulemaking, R.97-04-011/I.97-04-012.

scrutinized in the annual transition cost proceedings and that we expect the utilities to use their best efforts to find alternative uses for these assets.

11.7. Emissions Trading Credits

Emission trading credits are used by the utilities to offset certain air pollution emissions under a program established by federal statute. Excess emission trading credits not needed by the utilities can be bought and sold in a secondary market. We have generally found that 100% of the total net value of these credits (less only the sales costs) should be returned to ratepayers. These policies were adopted in D.95-12-051 (for PG&E) and in D.95-04-076 (for SDG&E). Both PG&E and SDG&E are subject to the Environmental Protection Agency's sulfur dioxide (SO2) emissions program. Edison's fossil-fired plants are subject to the South Coast Air Quality Management District's nitrogen oxide (NOx) emissions program through its Regional Clean Air Incentives Market (RECLAIM).

In terms of ratemaking, we have used the ECAC for PG&E and SDG&E to ensure that ratepayers receive this credit. Edison uses its Electric Revenue Adjustment Mechanism (ERAM) account for this purpose and has proposed to continue doing so in A.95-05-049, its 1995 ECAC proceeding, in which a Commission decision is pending. The ratemaking treatment of these credits is now in dispute, since it is likely that the ECAC and ERAM accounts will be eliminated or substantially modified.

11.7.1. The Utilities

PG&E recommends that, if sold, the economic portion of net excess emissions credits should be credited to the transition cost balancing account. Edison recommends that credits of record as of January 1, 1998 be market valued according to current year market prices and included as a credit against costs eligible for recovery through the transition cost balancing account. Edison proposes that when plants are market valued, the excess credits which have not yet been sold and are attributable to each facility could either be bundled with the plant or market valued separately. SDG&E recommends that if excess credits are sold prior to market valuation, the net proceeds should be credited to the transition cost balancing account, but believes that these values should be included in the market value of the plant unless they are sold prior to market valuation.

11.7.2. ORA and TURN

ORA recommends that any profit earned by the utilities from the sale of excess emissions credits which are not transferred to new owners through divestiture should be refunded directly to ratepayers, rather than being credited to the transition cost balancing account. TURN supports ORA's position.

ORA believes that simply crediting the value of these credits to the transition cost balancing account would defeat the Commission's stated purpose: to give the ratepayers the benefit of these sales. If these credits are used to offset transition costs, ORA believes that only shareholders would benefit, because such credits would serve to reduce the risk of transition cost recovery. Alternatively, ORA recommends that such proceeds be credited to a long-lived account, such as the account which will be established to track nuclear decommissioning expenses and revenues (as required by § 379), which would accomplish the Commission's intent by offsetting ratepayer costs.

11.7.3. Discussion

We will not adopt ORA's recommendation on this issue. The emissions credits do not fit the criteria listed in D.96-12-025, which established the Electric Deferred Refund Account for each utility. The sale of emissions credits results in a gain from a sale of utility property, rather than from utility overcollection or imprudent conduct. We agree with PG&E's assessment that sales of these assets are similar to sales of utility property, in which the gain on sale accrues to ratepayers. In D.97-04-024 and D.96-09-044, we determined that the appropriate way to flow a gain of sale of utility property to ratepayers is by crediting the proceeds to the transition cost balancing account. Similarly, crediting after-tax proceeds resulting from sales of emissions credits to the transition cost balancing account will help to ensure that the transition cost obligation can be recovered more quickly and the rate freeze ends more quickly.

By crediting such gains to the transition cost balancing account, we comply with § 367(b), which requires netting both above-market and below-market assets to determine the uneconomic piece of transition costs. Finally, crediting the transition cost balancing account rather than refunding these credits directly to ratepayers is consistent with our preference for the use of market-based mechanisms, in which the emissions credits are addressed during the market valuation process. To the extent that generating plant is retained, this credit should continue after the end of the transition period and will apply to offset post-2001 transition costs, as PG&E proposes.

11.8. Treatment of Land at Power Plant Sites for Divestiture

11.8.1. Utilities

PG&E states that it intends to package the relevant plant and associated generation assets, including land, in its divestiture offerings. This market valuation process would then result in a net credit or debit to the transition cost balancing account. As described above, PG&E believes that land must now be treated as depreciable property and proposes that all gains and losses realized through sale, spinoff, or appraisal of generation assets, including land, should flow back to ratepayers by way of the transition cost balancing account. PG&E believes this approach is consistent with TURN's proposal and states that to the extent the package is projected to be above-market, PG&E will accelerate amortization of the land, consistent with D.97-06-060.

In its divestiture application (A.96-11-046), Edison proposes to separate the land at its gas-fired fossil fuel sites as follows: 1) land necessary to operate the generating plant; 2) land to be sold separately; and 3) land to be retained by Edison for other purposes. Edison asserts that it has not yet determined the exact portion of land in each category and has therefore included all land at the generating stations as eligible for transition cost recovery. At market valuation or divestiture, Edison states that it will determine the appropriate disposition of the land and will then make the corresponding adjustments to the transition cost balancing account. Edison states that it has also identified a "proposal that would also allow the bidders for the plants to inspect the proposed property boundaries for themselves and propose minor boundary adjustments that may ease potential plant upgrade or repowering projects." (Edison's opening brief, p. 93.)

Edison recommends that land associated with transmission facilities should receive a full rate of return and should not be amortized on an accelerated basis. Edison explains that this land has been traditionally classified as generation assets in the vertically integrated utility. Edison proposes to retain land associated with fuel oil facilities until the ISO makes a determination as to the need for this dual fuel capability in the future. Edison recommends that if it is to retain these facilities for reliability purposes, they should be treated in the same manner as transmission assets; i.e., not subject to market valuation or accelerated depreciation. Edison recommends that all other land at its generating stations, whether proposed to be included in the divestiture transaction or not, should be classified as generation assets. Edison contends that no party, in any prior proceedings, has contended that it was improper to hold this land as generation assets. Edison agrees that this land eventually will be market valued and that the market valuation process will likely result in a credit to offset transition costs; however, Edison asserts that this determination cannot be made until divestiture is completed, at which time, Edison will know that boundaries of the divested land and any adjustments that might be required by various municipalities.

11.8.2.Intervenors

TURN argues that any land which is not included in the divestiture package must therefore not be required for the operation of the generating plants, by definition. This land should then be removed from rate base and treated as non-utility property. TURN recommends that such land should undergo market valuation as soon as possible and any net gains should accrue to ratepayers, who have been paying carrying costs on this investment for many years. TURN contends that this land should not be amortized at the beginning of the transition period and should not earn a rate of return prior to market valuation, because it is not needed for power plant operation or repowering and is therefore not utility property, a conclusion which TURN states is derived from Edison's position in the divestiture proceedings. TURN agrees that land related to transmission assets should not be market valued, but contends that land associated with fuel pipelines should be market valued and amortized at the reduced rate of return.

TURN maintains that none of the proposals for assigning differing rates of return to the various pieces of land can be implemented until Edison performs the necessary analysis of how much land should be assigned to each function or use at each plant. TURN recommends, therefore, allowing Edison to amortize only the book value of the land proposed to be divested until that analysis is completed. TURN recommends that Edison receive a reduced rate of return on all land until this analysis is complete. Upon completion, ratepayers would be refunded the return paid on land later found to be non-utility property and Edison would resume collecting a full rate of return on transmission-related land. In other words, TURN recommends that 1) land not needed for utility purposes would be removed from rate base on January 1, 1998, 2) the fair market value should be determined as quickly as possible, and 3) all net gains from increases in the land's value should accrue to Edison's ratepayers.

ORA supports TURN's recommendation to allow Edison to amortize only the book value of the land to be divested until further analysis is performed to accurately divide the land into pipeline-related land, transmission-related land, and other. Farm Bureau also supports TURN's recommendation to restrict Edison's recovery on the land it intends to retain. FEA recommends that any assets which have been used for generation functions in the past may be usable in other utility operations. Therefore, FEA maintains that it is questionable whether these assets are generation-related, and, in the case of land, whether these assets can be considered uneconomic. Enron also supports TURN's proposal.

11.8.3. Discussion

We have encouraged the divestiture of at least 50% of PG&E's and Edison's generation facilities in order to attempt to "resolve many, if not most, of the market power problems identified by the Department of Justice and FERC, and allow for a competitive market." (Preferred Policy Decision, mimeo. at p. 101.) To provide an incentive for these transactions, we allowed an increase in the reduced rate of return applicable to the utilities' non-nuclear and non-hydroelectric equity components of up to 10 basis points for each 10% of fossil generating capacity divested. These approaches were affirmed in D.96-12-088 and D.97-02-021. The Preferred Policy Decision provides this incentive only for the non-nuclear and non-hydroelectric equity components. PG&E and Edison should include proposals for computing and applying this incentive in their respective divestiture proceedings. PG&E and Edison should establish tracking accounts to track the differential in the rate of return as each 10% of fossil generating capacity is divested, which would then be applied to the reduced rate base.

Section 330(e) confirms the state's intent to reap the benefits of competition in the generation of electricity and § 330(l)(3) documents the Legislature's concern regarding market power. Furthermore,§ 367(b) requires market valuation "for those assets subject to valuation" by the end of 2001. It is indisputable, therefore, that market valuation and, in this particular case, divestiture, accomplishes two goals: 1) to ensure that "no participant in these new market institutions has the ability to exercise significant market power so that operation of the new market institutions would be distorted;" and 2) to transition the utilities from regulated status to unregulated status (§ 330(l)(2)). Both §§ 330 and 367 require that a netting calculation of all "above-market" and "below-market" transition cost assets be performed to determine the costs to be recovered. Section 330 requires that the transition to a competitive market be orderly, allow the utilities a fair opportunity to fully recover the costs associated with commission-approved generation-related assets and obligations, and be completed as expeditiously as possible. These two mandates demonstrate our duty to ensure that the market valuation process is structured as to obtain maximum value of the property.

In D.97-06-060, we found that the interests of both ratepayers and shareholders would be aligned in developing a methodology to collect transition costs as expeditiously as possible. Similarly, obtaining the maximum assessment of fair market value in an arms-length transaction benefits both the ratepayers and shareholders. Shareholders are not at risk for recovery of as many uneconomic costs and ratepayers may benefit by an early end to the rate freeze.

Edison indicates that it plans to divest only the "footprint" of land that its generation facilities occupy, but would give bidders the option of requesting more land as needed. The lands that Edison intends to retain are similar in nature to property that the utility previously held as Plant Held for Future Use (PHFU). We believe the principles underlying PHFU treatment apply equally to the generating plant-related land that Edison does not propose to divest with its generating plants. Edison believes that TURN's proposal should be dismissed as retroactive ratemaking and alleges that it is appropriate to retain the PHFU land until a favorable market arises for the land. At that point, Edison says, the utility will sell the land and apply proceeds from the sale to offset transition costs.

PHFU property may be included in a utility's rate base, as established in guidelines adopted as Appendix B in D.87-12-066, in Edison's 1988 general rate case. These guidelines clarify that, under certain circumstances, we will include PHFU in rate base. We have also determined that "[n]othing in this exhibit should be interpreted as precluding the ability of the ratepayers to recover gains on sales of plant that has at some time earned a return as PHFU." (D.87-12-066, mimeo. Appendix B at p. 4.)

In addition, § 728.1(c) sets forth standards for returning to ratepayers funds realized from a gain on sale of PHFU property. It requires that gains on sale of PHFU property that was included in rate base be allocated to customers in a manner consistent with Account 105 of the Uniform System of Accounts. It then directs that

> "the portion of the gains allocated to customers shall not be less than the amount the corporation has recovered through rates for the carrying costs and other expenses of the property during the period it was carried in the plant held for future use, and shall not exceed the gain on the sale, net of any tax, resulting from the sale."

It is reasonable to adopt TURN's proposal with certain modifications. By valuing a property right after it is taken out of rate base, the Commission could eliminate future uncertainty as to dividing the property's value pursuant to § 728.1(c). Assuming that the property had been in rate base since purchase, all gain in value since then would be attributable to ratepayers. Assigning value immediately might also immunize ratepayers from any speculation by the utility (e.g., if the utility waited until after the real estate market plunged to sell the property). Most importantly, calculating the gain in value of the land upon divestiture allows us to derive the necessary information to determine whether assets are or are not economic.

While Edison argues that retroactive ratemaking bars us from implementing TURN's proposal, we do not agree with this conclusion. We have previously concluded that an allocation of gain does not constitute retroactive ratemaking, since no adjustment is made to previously collected rates results. (56 CPUC 2d 4, 16.) Rather, we have imposed corrective actions to remedy past overcollections based on a utility's failure to comply with established accounting rules.

We direct Edison to allocate its land according to its function; i.e., transmission-related, fuel oil pipeline-related, and generating plant-related land, using a pro-rata analysis. The transmission-related land will receive the full rate of return and will not impact transition cost recovery. Edison's pro rata approach should be filed on March 2, 1998, in its appraisal application. Consistent with our approach toward fuel oil inventory, Edison should amortize the pro-rata portion of the land associated with fuel-oil pipeline and should include its proposal for the treatment of this land in the proposal for fuel oil inventory, to be filed on March 2, 1998, as discussed previously. All other land, traditionally classified as generation, but not divested with the plant, will be removed from rate base as of January 1, 1998. Only the book value of the land which is proposed to be divested and which is attributable to fuel oil pipelines will be amortized in the transition cost balancing account at the reduced rate of return until further analysis confirming these pro-rata approaches is complete and appraisal of the land is completed. Thus, other than land which is allocated to the transmission function and fuel oil pipelines, all generation-related land attributable to plant which is proposed to be divested should be removed from rate base as of January 1, 1998. We will order Edison to adjust its transition cost balancing account once the land is fully analyzed according to its various functions and undergoes market valuation. In this way, any gains can be quickly applied to offset transaction costs.

If not sold or market valued prior to divestiture, the date of divestiture is a reasonable date for this valuation to occur. At that point, we will know exactly what property the winning bidder requires and any adjustments that are required by various municipalities. The land can then be appraised and valued and the appropriate credits can be recorded in the transition cost balancing account. We are not convinced that there are such unique qualities to this land which would argue that we should wait until market valuation procedures for retained assets are in place. As with our prior examples, land is very different from power plants. We will review such assessments in the annual transition cost proceedings for reasonableness. This is a simple, uniform policy to apply, particularly because PG&E has already stated that it intends to include the land surrounding its power plants for divestiture, other than land needed for other utility purposes.

11.9. Step-up Transformers and Generation Radial Tie-Lines

On April 29, 1996, PG&E, Edison, and SDG&E filed a joint Petition for Declaratory Order (Docket No. EL96-48) with FERC, which asked for confirmation of a proposed delineation of certain facilities as either local distribution or transmission facilities. Edison proposed that all generation step-up facilities, except those at the San Onofre Nuclear Generating Station (SONGS), be reclassified for ratemaking purposes as generation. Edison also proposed that the SONGS step-up transformers and generation radial tie-lines connecting generators to the transmission grid remain classified as transmission for ratemaking purposes. In its comments, this Commission supported this proposed delineation, but recommended classifying the SONGS step-up transformers and generation radial tie-lines as generation. On October 30, 1996, FERC issued its Order in Docket No. EL96-48, which adopted the proposed delineation of facilities with this Commission's modifications. In D.97-05-053, we granted Edison's petition to modify D.96-01-011 and D.96-04-059, and allowed Edison to add approximately $18.7 million of sunk costs associated with SONGS' step-up transformers to SONGS sunk costs. (D.97-05-053, mimeo. Conclusion of Law 3 at pp. 9 -10.)

No party disputes this issue. Since FERC has already reclassified generator step-up transformers and generation radial tie-lines as generation, it is reasonable to use that classification for transition cost ratemaking purposes. These assets should be added to the net book value of associated plant.

12. Nuclear Generation Transition Costs

Generally, the revenue requirement associated with nuclear facilities is not an issue to be determined in this proceeding. The amount of sunk costs and ICIP treatment for Diablo Canyon was considered in D.97-05-088; the treatment of Palo Verde Nuclear Generating Station was determined in D.96-12-083; and the treatment of SONGS was considered in D.96-01-011 and D.96-04-059. However, certain issues related to nuclear generation transition costs have been raised in Phase 2, including whether transition cost recovery for differences between ICIP costs and Power Exchange revenues is allowed for PG&E. We do not address issues previously addressed in D.97-08-056. Nuclear sunk costs are already being amortized at an accelerated rate, consistent with the respective decisions.

12.1. Diablo Canyon

In A.96-12-009, PG&E proposed to recover ICIP costs by way of a separate nonbypassable charge. PG&E has also expressed, in this proceeding, its willingness to recover these costs in the transition cost balancing account (RT: 2241; 2964-2965). D.97-08-056 precludes the use of a separate, nonbypassable charge for this cost.

PG&E explains that in D.97-05-088, we adopted a fixed ICIP amount which reflects the cost to ratepayers of kilowatt hours received from the plant. Power Exchange revenues from Diablo's output would be used to offset this fixed ICIP price, but to the extent Power Exchange revenues are greater or less than ICIP, the difference would result in a debit or credit to the transition cost balancing account. PG&E asserts that this relationship is consistent with and authorized by the Rate Restructuring

Settlement, which provides that if PG&E's actual incremental costs exceed the fixed ICIP prices, this difference (between actual and ICIP) would not be recoverable in the transition cost balancing account. PG&E does not believe that the Rate Restructuring Settlement precludes either the recovery or the crediting of the difference between ICIP and Power Exchange Revenues, as TURN contends.

TURN maintains that because the Rate Restructuring Settlement reads, in relevant part, that "[n]one of Diablo Canyon's incremental costs would be eligible for recovery through the CTC," such recovery should, in fact, be banned. ORA does not believe that the Rate Restructuring Settlement is a document which binds this Commission in any way.

We agree with PG&E. As contemplated in both AB 1890 and the Preferred Policy Decision, it is the ongoing ICIP costs which are compared to the Power Exchange, and differences in revenues or costs are either credited or debited to the transition cost balancing account. Actual costs are not compared to the market clearing price for purposes of determining these ongoing transition costs. If the market-clearing price is below ICIP costs, this difference is debited to the transition cost balancing account. PG&E is at risk for any actual, incremental costs which are greater than ICIP. Similarly, if the market clearing price is greater than ICIP costs, this difference is credited to the transition cost balancing account. If actual costs are below ICIP costs, PG&E may retain the difference.

12.2. San Onofre Nuclear Generating Station (SONGS 2&3)

Edison states that it is making various necessary repairs to low-pressure steam turn rotors and exhaust hoods, which it asserts are necessary to maintain the safe and reliable operation of SONGS 2&3. Edison contends that shareholders made this investment with no guarantee of recovery and furthermore that there is no guarantee that Edison will realize any improvements in the capacity and output of SONGS. Edison asserts that any improvements which do occur would offset efficiency losses due to the units' aging. Edison notes that SONGS 2&3 have historically operated above and below their rated capacity during the last 10 years of operation. SDG&E agrees with

Edison's position that "the rated capacity of the unit is simply the vendor's guarantee that given a set of variables, their guarantee to the purchaser of the plant is that it will perform at least at this level." (RT at 1546.)

As a general proposal, TURN recommends that no ICIP costs be recoverable in the transition cost balancing account for any output significantly above current nameplate capacity due to plant retrofits. TURN makes this recommendation specifically for SONGS, because it believes that the repairs are likely to increase the capacity above nameplate capacity. ORA supports TURN's position.

EPUC recommends that the recovery of ICIP should be consistent with the requirements of the SONGS settlement, but notes that the limit for SONGS recovery is the ICIP compensation. EPUC therefore proposes that in the event that Power Exchange or other revenues exceed the ICIP, the transition cost balancing account be credited with the excess amount, which would then reduce transition costs. Similarly, in the event that there is a shortfall in revenues below the eligible ICIP level, EPUC recommends recovering this shortfall through the transition cost balancing account.

Under the terms adopted in D.96-04-059, Edison and SDG&E will recover the forecasted costs of operating the plant if SONGS 2&3 operate at a capacity factor of 78%. Actual costs above ICIP (i.e., if capacity is less) are not recoverable from ratepayers, while actual costs below ICIP (i.e., if the plant operates at a higher capacity factor) do not benefit ratepayers. Thus, if the plant's capacity were increased by these repairs, it would produce more kilowatt hours than it would have compared to the capacity factor adopted in D.96-04-059. Depending on the Power Exchange price, an increase in produced kilowatt hours has the potential to increase the transition costs claimed if the Power Exchange price is less than the forecasted ICIP price. Similarly, if the Power Exchange price is greater than forecasted ICIP prices, the increase in capacity has the potential to offset transition costs.

We do not choose to interfere, in this decision, with the balance of risk and rewards that was adopted concerning the ratemaking treatment of SONGS 2&3. These retrofits were undertaken for purposes of plant safety and reliability, *not* to increase plant capacity per se. Recovery of the differences between ICIP prices and Power

Exchange clearing prices was intended by the Preferred Policy Decision and provided for in AB 1890. Therefore, we will rely on the ICIP prices adopted in D.96-04-059 to compute any necessary transition cost recovery or offsets.

Comparison of ICIP costs with the market-clearing price is different for purposes of computing ongoing transition costs, if any, related to the Palo Verde Nuclear Generating Station. In D.96-12-083, we established balancing account treatment for these ICIP costs, consistent with the settlement agreement proposed by the parties and adopted in that decision. Because of this balancing account treatment, we will compare Palo Verde's incremental operating costs as billed by the Arizona Public Service, the plant's operator, with the market-clearing price, rather than the fixed ICIP costs approach which we have implemented for Diablo Canyon and SONGS 2&3.

13. Fuel and Fuel Transportation Contract Transition Costs

Section 367(c) includes fuel and fuel transportation costs as going forward costs, which must be recovered from market revenues and which are specifically excluded from transition cost recovery, with two limited exceptions identified in § 367(c)(1) and (c)(2). Despite this guidance, these issues have generated great controversy.

13.1. PG&E

For generating facilities that are designated as must-run by the ISO, PG&E asks for the opportunity to seek recovery of all fixed fuel and fuel transportation costs through the transition cost balancing account if these costs are not recovered through the ISO contracts. PG&E explains that it would reserve a placeholder for these costs and recovery of any costs not covered by ISO revenues should be considered by the Commission if and when PG&E actually seeks such recovery. As discussed previously, we deny this request.

For non-must-run generating facilities, PG&E is not seeking transition cost treatment of any uneconomic costs of the demand charge, customer access charge and Transwestern reservation charge associated with these facilities, consistent with its agreements in the Rate Restructuring Settlement. However, PG&E is seeking a placeholder to allow recovery of the uneconomic costs of the Interstate Transition Cost

Surcharge (ITCS) and geothermal minimum take-or-pay obligations associated with the non-must-run facilities. PG&E identified these costs as $255.7 million (Geysers steam purchases of $215.2 million and ITCS costs of $40.5 million). PG&E does not seek recovery of these costs as of January 1, 1998, but instead proposes to seek Commission approval if they are actually incurred during the transition period, to the extent these costs are not otherwise recovered from Power Exchange or ISO revenues.

The audit report accepted these costs as eligible for transition cost recovery, but proposed to increase the Geysers contracts by $53.8 million, which are year 2000 costs for this contract which were omitted from the filing. The auditors also questioned the ITCS amount, because we have not previously approved this amount.

PG&E asserts that AB 1890 gives the Commission the option to determine that categories of fuel costs that are going forward costs and fixed obligations are eligible for transition cost recovery for non-must-run plants, particularly in light of the use of the term, "generation-related assets and obligations" in § 367. PG&E also asserts that this language reflects the Preferred Policy Decision, which allows recovery of "fixed obligations directly related" to the generation asset. (Preferred Policy Decision, mimeo. at p. 115.)

PG&E maintains that ITCS costs are comparable to a generation-related regulatory asset and should be eligible for transition cost recovery. These costs are a result of PG&E entering into various interstate gas transportation contracts prior to the unbundling of the gas industry. PG&E explains that it entered into these contracts to ensure that it could provide services needed for its gas users, including its own fossil-generation facilities (or Utility Electric Generator, UEG). Because it entered into these contracts to provide bundled service to its own electric generation, a portion of the capacity under these gas contracts was expected to be allocated to PG&E's UEG. Capacity brokering and the ITCS balancing account delayed the payment of these costs and PG&E now asserts that these gas transportation contracts should be categorized as a generation-related asset and cannot be considered a going-forward cost. PG&E asserts that these costs are given balancing account treatment and any undercollection of ITCS from noncore customers will be allocated to the noncore customers in the next Biennial

Cost Allocation Proceeding (BCAP); therefore, these costs represent a fixed obligation of noncore customers. PG&E admits that its UEG pays these costs through a volumetric charge, but states that it is possible these costs could be included in the demand charge for the next BCAP cycle.

PG&E explains that the auditors questioned $40.5 million related to ITCS only because this amount has not received Commission approval for 1998 and 1999. PG&E expects an allocation of ITCS costs in the next BCAP similar to the $40.5 million allocated to PG&E's UEG in the 1996-97 cycle.

PG&E also believes that fixed geothermal steam fuel-related obligations are eligible for recovery in the transition cost balancing account, as discussed in Section 16. PG&E seeks authorization to request recovery of these costs if they are not recovered in the market. PG&E believes that to the extent operations of its geothermal facilities are suspended, it would incur take-or-pay costs, which would be a fixed obligation. Secondly, PG&E explains that § 367(c) applies specifically to fossil fuel facilities and not to geothermal facilities. PG&E states that from a policy perspective going-forward costs of geothermal facilities should be treated differently from going forward fossil costs, and explains that geothermal steam contracts are unique in that there is no other use for this steam.

13.2. Edison

Section 367(c)(2) allows Edison to recover 100% of the uneconomic portion of the fixed costs paid under fuel and fuel transportation contracts, with the following requirements: 1) the fuel and fuel transportation contracts had to be executed prior to December 20, 1995 and 2) these contracts must be determined to be reasonable by this Commission. As of January 1, 1998, Edison estimates that it will incur $840.5 million in cumulative, unavoidable fixed costs under fuel and fuel transportation contracts for the transition period ($389.9 million in gas contracts and $450.7 million in coal contracts). These costs would be netted against the market value of the fuel to obtain the uneconomic portion, or the amount to be collected through transition cost recovery. Edison states that it captures the market value of the gas contracts, which are credited against transition costs and thereby reduce the total amount to be collected. Edison does not believe that there is a ready market for coal which would allow similar calculations to be made.

Similar to the position of several intervenors, Edison maintains that ITCS gas costs are a going forward cost, and therefore should be recovered through market prices. However, Edison states that if we find that PG&E's ITCS costs can be recovered through the transition cost balancing account, the same treatment should be afforded to Edison.

Edison explains that its fuel and fuel transportation contracts are eligible for recovery under the exception granted in § 367(c)(2). Edison proposes to determine its unavoidable gas costs monthly and to book costs associated with contracts pending reasonableness review to the transition cost balancing account, subject to later true-up. Edison contends that this approach is reasonable because it is consistent with current ECAC procedures, it will not impact Edison's ability to recover such costs during the transition period, and ratepayers will be unaffected because of the rate freeze. Edison states that a settlement agreement related to Canadian gas reasonableness issues has been reached with ORA and submitted to the Commission in A.93-05-044 *et al.*, which would make the necessary reasonableness findings, if adopted by the Commission.

Edison asserts that all unavoidable fuel contract costs found reasonable by this Commission must be eligible for transition costs recovery. Edison explains that many of its long-term gas contracts include terms which require Edison to pay the supplier regardless of the quantity of gas which is actually scheduled. Edison considers these costs unavoidable. Edison also explains that contracts which do not require Edison to schedule minimum quantities or make fixed payments regardless of the quantity of gas taken are not considered unavoidable or fixed obligations, and therefore does not request transition cost recovery for these costs.

Edison entered into long-term coal contracts to supply its Four Corners and Mohave generating stations. Edison states that certain costs related to these contracts are unavoidable or fixed and furthermore, certain costs may arise in the future which become unavoidable. For example, Edison has entered into contracts to supply coal to the Mohave generating station, which requires Edison to pay certain costs regardless of the quantity of coal taken. Variable costs are costs that depend on the quantity scheduled and can be avoided if Edison does not schedule any coal under its contracts.

As we have previously explained, Edison takes three steps in determining fossil-related transition costs. First, Edison determines eligible transition costs (including fuel and fuel transportation contracts) and then nets out benefits associated with emissions credits and allowances and gas market revenues. Second, Edison calculates offsets to the net eligible transition costs, which includes credits such as its proposed gas purchase credit. The gas purchase credits are designed to equal the market value of Edison's gas contracts that are used to provide gas for electric generation. Edison proposes to determine credits separately for must-run and non-must-run units. Finally, these offsets are deducted from the net eligible transition costs to arrive at the uneconomic costs which Edison believes it should have the opportunity to collect through transition cost recovery.

Under Edison's proposal, the market value of gas is used to determine the going forward costs recoverable from market revenues, which help to offset the unavoidable costs of Edison's long-term gas supply and gas transportation contracts. Edison states that this credit is designed to approximate the amount of net revenue that Edison would have received if it sold its gas at market prices rather than using the gas for generation.

Edison explains that to determine whether there will be an offset to eligible transition costs, the variable costs of fuel must be estimated for both gas-fired and coal-fired generation. In addition, if Edison resells to third parties any gas transportation or gas that it must purchase, this results in a benefit that offsets these eligible transition costs. The net eligible transition cost determination is a result of offsetting eligible transition costs with the appropriate benefits (including emissions credits). We have already disposed of Edison's proposed incremental capital cost credit, its proposed 150 basis point equity earnback, and its Power Exchange/ISO revenue credit, and will now address its proposed gas purchase credit.

The gas purchase credit is an offset to the calculation of net eligible transition costs and reflects the fact that Edison's actual variable costs may differ from the costs Edison would have paid if it had purchased its gas and gas-related services in the gas market (also called the gas dispatch price).[21] The dispatch cost is defined as the forecast market value of the gas and gas transportation consumed in order to generate the forecast gigawatt hours. Edison believes that this gas purchase credit is necessary for two reasons: 1) Edison has entered into gas and gas transportation contracts under which it pays an unavoidable (fixed) cost and a variable cost, and this variable cost may be below the market clearing price for the same commodity or service; and 2) Edison also uses gas and gas transportation purchased under must-take contracts with very low variable costs. Edison states that whether or not it earns market revenues to cover its incremental costs, the gas purchase credit would be used to offset eligible transition costs so that Edison's distribution customers would receive the economic value of these contracts that were entered into on their behalf.

Edison explains that the gas purchase credit represents the portion of its unavoidable gas contract costs which are recoverable from the market; in other words, these costs are economic and so are credited back to offset transition costs. Edison believes that the gas purchase credit must be calculated differently for must-run and non-must-run plants. We note that Edison has an application pending to divest all of its gas-fired plants; once divestiture occurs, it is only the coal-fired plants that will be the subject of this recovery requirement.

For must-run plants, Edison proposes to calculate its gas purchase credit differently, because it has proposed a Power Exchange revenue crediting mechanism based on different variable costs. The actual workings of the proposed gas purchase credit appear to be the same for both must-run and non-must-run plants, however,

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[21] This would be an important step in Edison's revenue crediting proposal, because as Edison explains further, in calculating its incremental costs to determine the Power Exchange/ISO revenue credit, the gas burned is valued at the gas market price or dispatch price of gas. We have rejected this proposal.

except for an adjustment which Edison states is necessary because the gas dispatch cost is based on a deemed quantity of gas from the unit heat rate curves, whereas the variable cost of gas is based on the actual quantity of gas consumed at the unit. Edison states that whether or not there is a Power Exchange/ISO revenue credit available for must-run units, the gas purchase credit must offset eligible transition costs so that the economic value associated with these long-term fuel contracts is passed on to ratepayers.

Edison forecasts its 1998 variable gas costs, based on the 1998 forecast gas burn, the California border price forecast, the forecast gas supply basin prices, and the forecast interstate and intrastate transportation rates. Edison sequences the available gas supplies based on incremental cost to meet its total forecast gas demand, which is the methodology used in its most recent ECAC forecast. Edison then calculates its forecast of 1998 Gas Dispatch Costs based on the California border gas price forecast. For units served by Southern California Gas Company (SoCalGas), the forecast border price plus the forecast SoCalGas tariff rate (intrastate transportation rate) plus the municipal surcharge equals the forecast gas dispatch price. For Mandalay Generating station, which is under a bypass deferral agreement with SoCalGas, the forecast contract rate plus the municipal surcharge is added to the forecast border price to obtain the gas dispatch price. For Cool Water generating station, which is served directly by the Kern River and Mojave interstate pipelines, the forecast gas dispatch price assumes gas will be transported to Cool Water on the Mojave pipeline. The forecast gas dispatch cost for 1998 is obtained by multiplying the monthly gas dispatch price at each station by the forecast gas burn at that station.

For variable coal costs, Edison estimates its forecast using the same methodology that Edison uses in ECAC proceedings. This methodology begins with recorded coal costs and forecasts future coal costs based on forecast inflation rates for the various cost components. Edison does not believe there is any portion of the unavoidable costs of the coal contracts which is economic, because there is no market available for the sale of coal received under these contracts. Edison asserts that there cannot be a market because the coal mines and the coal plants are remote and lack access to coal markets.

Two major issues have been raised regarding the gas purchase credit. EPUC and CIU argue that this credit should always be equal to or greater than zero. CIU is concerned that under Edison's gas purchase credit proposal, if the variable cost of gas were to exceed its estimate of the market price, it appears that Edison would seek transition cost recovery for certain gas costs. EPUC also questions the use of the intrastate transportation cost in calculating the gas purchase credit and maintains that if it is used in establishing the dispatch price, it should never be lower than Edison's actual intrastate transportation cost. Edison counters these concerns by stating that because the dispatch price is based on the California border price and actual intrastate transportation rates, the actual variable gas costs are not likely to exceed the gas dispatch price on a monthly basis, if Edison continues to use gas under its existing long-term contracts. Edison also asserts that a negative credit is unlikely because Edison's incentive is to reduce the level of transition costs.

Because Edison sequences the purchase of available gas supplies based on incremental cost to meets its forecasted gas demand, it would not utilize its long-term contracts if the variable costs incurred under these contracts exceeded the gas dispatch price, because it would be more economical for Edison to purchase gas at current market prices. However, Edison objects to limiting the gas purchase credit to be at least equal to zero. Edison maintains that it is possible for the gas purchase credit to decline as Edison divests its plants, buys out or buys down to market its long-term gas contracts, or elects to sell its gas supplies and gas transportation capacity on a shorter-term basis. Edison states that the gas purchase credit is just one of the offsets to fossil net eligible transition costs. Edison has testified that, in the aggregate, such offsets cannot be less than zero; thus, a negative gas purchase credit cannot result in a recovery of more than the net eligible transition costs. (RT: 2249-2250.)

The gas dispatch price used in the above calculations is based on published tariffs and market indices and is a proxy for actual market price of gas. In general, Edison agrees with EPUC that the "deemed" intrastate transportation cost and the actual intrastate transportation costs will be identical, but would like to allow for the possibility of differences. Edison expects that it is possible to negotiate a rate with its supplier that is less than tariff rates, which would then increase the gas purchase credit. EPUC contemplates a situation which would result in rates higher than tariff rates, which have the potential of increasing transition costs. While Edison expects that this is an unlikely outcome, it objects to EPUC's recommendation that the cost used in the benchmark (i.e., the gas dispatch price) should never be lower than Edison's actual intrastate transportation costs.

Edison believes that its coal supply and coal transportation have unique characteristics affecting the determination of uneconomic costs. Because there is not an active competitive market for coal supplies, unlike gas generation, Edison assets that it is impossible to determine the uneconomic or economic portion of the coal contract costs in isolation. Edison therefore proposes to use the economics of the entire coal plant and its output as the best proxy for determining the uneconomic portion of the fixed costs of the coal contracts. Edison recommends that all fixed, unavoidable costs of the coal contracts be considered eligible for transition cost recovery and that the market value of the generation associated with Four Corners and Mohave be credited to offset these costs; this would result in only the uneconomic generation costs being recovered as transition costs. Edison believes this approach would be consistent with market valuation of these facilities, in that it expects the coal contracts would be included with the plants and the bid price would reflect any uneconomic features of the coal contracts.

Edison asserts that the take-or-pay obligations of the Four Corners coal contract represent a fixed cost eligible for recovery, because payments for the minimum quantity are required and unavoidable. Edison disputes TURN's contention that the take-or-pay obligation is not eligible for transition cost recovery unless the take-or-pay limit is reached. Edison also disputes TURN's contention that the costs that Edison may incur under its existing coal supply contracts for mine closings and reclamation are speculative and should be excluded. Edison believes that to the extent it has any liability for mine closing and reclamation costs, which are in dispute, and actually incurs costs, those costs should be recoverable as transition costs. Edison also explains that any recovery of employee retirement costs will be based on actual costs, rather than estimates.

The auditors questioned various contracts, because they have not yet been approved by the Commission, and proposed other adjustments related to calculation errors. These adjustments would reduce unavoidable gas contract costs from $389.9 million to $70.7 million. Similar adjustments for coal contracts would reduce the amounts from $450.7 million to $419.1 million. The auditors include adjustments to the coal contracts to reflect the fact that Edison is not specifically responsible for certain retirement costs and mine closing costs under the Peabody and BHP coal mine contracts. The auditors acknowledge that Edison is disputing these items with the suppliers and may ultimately be responsible for some or all of these costs.

The auditors also question the allocation of fixed unavoidable costs under the Peabody contract, because they believe this allocation overstates Edison's long-run unavoidable obligations. The audit report explains that Edison's methodology is only accurate assuming normal operation of the Mohave power plant and recommends that we review Edison's assumptions regarding this contract's fixed and variable costs. Edison assumes that unavoidable labor and material costs are independent of delivered coal tonnage over the life of the contract. The auditors clarify that while this assumption may be reliable for short-term variations in tonnage, it may not be true for long-term tonnage change. The auditors believe an adjustment may be necessary, but cannot quantify it, because Edison's contract cost forecasting model assumes labor and material costs are independent of tonnage.

13.3. SDG&E

SDG&E seeks recovery of fixed transportation costs allocated to its UEG, pursuant to its BCAP. SDG&E estimates these costs at $38.7 million, excluding natural gas storage costs. SDG&E concurs with the audit adjustment in removing the storage costs. The auditors question the remaining UEG costs, which they explain might not be recoverable if SDG&E's plants are not considered reliability plants and because the regulatory foundation for their inclusion is unclear.

SDG&E asserts that these costs represent a regulatory obligation which SDG&E will incur whether or not its units are designated must-run by the ISO. SDG&E has proposed that all of its non-nuclear generating units are needed for reliability purposes and therefore expects to enter into must-run agreements with the ISO, which will include the BCAP fixed transportation expense. To the extent that must-run agreements are not executed for certain units by the ISO, SDG&E would then decide whether to operate those plants or shut them down. SDG&E acknowledges that if it chooses to operate these plants, SDG&E would be at risk for the BCAP fixed transportation costs as a going forward cost.

However, SDG&E states that if it decides to shut down these units, the BCAP fixed transportation costs would then be a regulatory obligation recoverable as a transition cost. Furthermore, SDG&E concurs with PG&E's position and states that to the extent a plant is designated as must-run and all costs are not fully recovered by the ISO or Power Exchange revenues, Commission-approved costs should be eligible for recovery in the transition cost balancing account.

13.4. ORA

ORA recommends that for non-must-run units, fixed costs related to fuel and fuel transportation contracts should be eligible for transition cost recovery only for Edison and then only to the extent that these costs are reasonable and uneconomic. ORA states that Edison's fixed fuel contract costs can be considered uneconomic only if Power Exchange revenues are less than all going forward costs, and the uneconomic amount is the difference between the Power Exchange revenues and all going forward costs.

ORA agrees the proposed settlement agreement if adopted in A.93-05-014 *et al.*, would resolve the issues of reasonableness of Edison's gas supply and gas transportation contracts and would describe the aspects of the contracts which we should consider reasonable for transition cost purposes. ORA explains that the portion of the reasonable costs that are uneconomic would be determined through the operation of the revenue crediting mechanism. According to ORA, the proposed settlement would resolve cost allocation issues associated with any buy-downs or buy-outs of these contracts. If the settlement is not adopted, reasonableness reviews would be necessary in the annual transition cost proceedings.

ORA is particularly concerned regarding the treatment of fixed uneconomic coal contract costs, because Edison is planning to divest all of its gas-fired fossil plants. Edison has identified these fixed costs as approximately $108 million in 1998. ORA considers only that portion of fixed fuel and fuel transportation costs which cannot be recovered from the Power Exchange to be uneconomic, while Edison defines all fixed fuel and fuel transportation costs associated with coal take-or-pay arrangements to be uneconomic. Using its methodology and Edison's estimates for 1998, ORA estimates that Power Exchange revenues compared with all going forward costs, including the fixed coal contract costs, will recover all but $2.3 million of the fixed coal contract costs.

ORA asserts that PG&E and SDG&E should not be allowed to recover any fixed costs associated with gas supply or transportation, because it is possible to manipulate fixed costs by converting variable to fixed charges. ORA maintains that if PG&E does not generate electricity from its gas-fired plants after January 1, 1998, it will not incur ITCS costs, which ORA maintains PG&E's electric department has no obligation to pay. ORA explains that these costs are not caused by electric restructuring, but were the result of gas industry restructuring and are costs faced by all competitors in the generation market. ORA thinks that PG&E's fixed take-or-pay costs associated with geothermal fuel are analogous to fixed fuel costs of fossil plants, and asserts that these costs should not be recoverable through the transition cost balancing account; rather, these costs should become part of the geothermal revenue requirement, to be established in A.96-07-009. As discussed in Section 16, ORA recommends that only credits resulting from the difference between Power Exchange revenues and the geothermal revenue requirement should flow through the transition cost balancing account.

13.5. TURN

TURN believes that our determination of fuel contract costs and their ultimate recovery is one of the most critical issues in this proceeding. TURN agrees with ORA that Edison may recover fuel and fuel transportation charges through transition cost recovery only to the extent that the Power Exchange price does not cover all going forward costs, including fuel and O&M costs. TURN asserts that Edison's take-or-pay costs are not stranded costs unless the take-or-pay obligation is actually incurred. In addition, TURN maintains that Edison's coal plants produce electricity at per kilowatt-hour costs that are below the expected Power Exchange price, even when the take-or-pay costs are included. TURN therefore asserts that it is unreasonable that Edison receive funding through transition cost recovery for a plant that is actually economic.

TURN also asserts that the appropriate cut-off date for considering the contracts reasonable is April 20, 1994, the date the electric restructuring rulemaking was issued. TURN observes that Edison's gas service with Southwest Gas was renegotiated on November 29, 1995. Prior to this time, Edison took tariffed service from Southwest Gas, which included a fuel price based entirely on volumetric usage. The new contract includes a fixed charge rate component, which now may be eligible for transition cost recovery. TURN looks askance at these facts and asks that the Commission consider the dates of contract execution in its determination of reasonableness.

TURN recommends excluding the potential charge for reclamation and closure costs associated with Edison's coal contracts from transition cost recovery. While TURN acknowledges that Edison is seeking a placeholder in the transition cost balancing account for these costs, should they be incurred during the transition period, TURN recommends that they be deemed presumptively unreasonable. TURN maintains that Edison should be required to make a detailed showing of any actual costs incurred in this regard. TURN explains that this higher standard is reasonable is because this category of risk is the product of Edison's choice to invest in coal plants.

TURN explains that, with few exceptions, every fossil fuel generation plant operator must pay to transport fuel to its power plants and contends that PG&E and SDG&E are not allowed to recover fuel costs under AB 1890, but must recover them from the market. TURN asserts that the dispatch cost assigned to a plant under regulation is not useful in terms of determining what is variable and fixed in the competitive generation market after January 1, 1998. Rather, TURN recommends that the bid price is the relevant information to consider and that recovery of ITCS costs through the transition cost balancing account would allow PG&E and SDG&E to make lower bids into the Power Exchange than they would otherwise be able to make if they had to recover all their costs from the Power Exchange price. Furthermore, TURN notes that PG&E has acknowledged that the Gas Accord's provisions (adopted in D.97-08-055) dispose of the ITCS cost issue.

13.6. FEA

FEA agrees that certain of Edison's fuel and fuel transportation costs are eligible for transition cost treatment under § 367(c)(2), but PG&E and SDG&E must recover these costs through the market as going forward costs. FEA asserts that the utilities have a duty to mitigate such costs, which cannot be considered an obligation for purposes of transition cost recovery. FEA maintains that the specific provisions of § 367(c) override the broad definition of costs eligible for transition cost recovery in § 367. FEA recommends excluding from transition cost recovery any costs whose eligibility for transition cost recovery depends on the need for plant reliability until that need has been finally determined.

FEA agrees that until costs are determined to be reasonable, Edison's fuel and fuel contracts are not eligible for transition cost recovery. FEA also recommends that certain coal mine closing and reclamation costs, as well as associated employee retirement costs, be ineligible for transition cost recovery at this time, because Edison is disputing whether it is liable for these costs.

13.7. CIU

CIU agrees with FEA that only Edison's fuel and fuel transportation costs are eligible for recovery, pursuant to § 367(c)(2). CIU concurs that PG&E's and SDG&E's fuel costs are excluded as going forward costs, because the general language of § 367 is expressly limited by the more specific language of § 367(c)(2). CIU disputes PG&E's

contention that take-or-pay costs associated with geothermal steam contracts are eligible for transition cost recovery. These costs do not fall under § 367(c), because they are not fossil units; nor can they be considered eligible for recovery under § 367, CIU contends, because these are contractual obligations, rather than a generation facility, nuclear settlement, purchased power contract, or regulatory asset.

CIU agrees that ITCS costs are a going forward cost. CIU explains that demand charges paid to SoCalGas and PG&E for intrastate transportation pipelines are not eligible for transition cost recovery except under certain limited circumstances. For Edison, CIU contends that these demand charges may be eligible only if they are part of a fixed transportation contract entered into prior to December 20, 1995 and cause the cost of electricity generated by the facility to be uneconomic. For PG&E and SDG&E, even if such demand charges are "akin" to generation-related obligations, CIU contends they cannot be included in the uneconomic portion of net book value of fossil plants, as provided for in § 367(c).

CIU concurs with other intervenors that Edison's proposed treatment of coal and gas contracts is inappropriate and has the potential of increasing transition cost recovery. CIU recommends a very limited application of § 367(c)(2) regarding Edison's coal contracts: if Power Exchange revenues (including revenues derived from sales of ancillary services and other products to the ISO) exceed Edison's costs of producing power from these plants (including net book value, return, going forward costs, and fixed fuel costs), no costs associated with these plants would be added to the transition cost balancing account; thus, these contracts would be eligible for recovery only to the extent that Power Exchange revenues derived from all fossil-fuel facilities are insufficient to recover the costs associated with these facilities. After market valuation, the positive or negative net value of the plants would be credited or debited to the transition cost balancing account.

13.8. EPUC

EPUC agrees with ORA that our review of Edison's gas costs must focus on determining which costs are fixed, which of those fixed costs are uneconomic, and which costs are reasonable. EPUC also agrees that our acceptance of the settlement pending in A.93-05-044 *et al.* will ultimately determine the reasonableness of the subject contracts; however, there may be certain accounting issues which must receive further consideration in the annual transition cost proceeding. EPUC maintains that Edison's gas purchase credit should have a safeguard and never be recorded as less than zero. Without this safeguard, EPUC believes Edison would recover more than the statute allows for the uneconomic portion of the fixed gas costs. The intrastate gas transportation rate is a component of both the gas purchase credit calculation and the Power Exchange/ISO revenue credit calculation. EPUC recommends using identical rates in the dispatch gas price (to calculate the gas purchase credit) and the actual gas price (to calculate the Power Exchange/ISO revenue credit). EPUC believes this approach will ensure consistency and avoiding any mismatching between booked costs and revenues.

13.9. IEP

IEP recommends that for those units classified as must-run by the ISO, the only going forward costs eligible for recovery in the transition cost balancing account, including fuel and fuel transportation costs, are those costs incurred in the hours when the ISO actually calls upon the plants to provide the relevant services, not for the duration of the contracts. This recommendation is further limited to the uneconomic costs, i.e., those costs not recovered through market revenues.

For PG&E's and SDG&E's non-must-run plants, IEP contends that no fuel and fuel transportation costs are eligible for transition cost recovery, because these are going forward costs. For Edison's non-must-run plants, only those costs that Edison demonstrates are within § 367(c)(2) are eligible for transition cost treatment; i.e., such costs must be uneconomic and must be found reasonable by this Commission. IEP asserts that Edison's proposed Mohave and Four Corners coal costs are not necessarily uneconomic, that the Canadian gas purchase and transportation contracts have not been found reasonable, and that the Wheeler Ridge Access charges are not uneconomic; these costs therefore are not eligible for transition cost treatment.

IEP states that ITCS costs are transition costs PG&E incurred as part of gas unbundling, and therefore are an obligation of its gas department. IEP argues that these costs cannot be regulatory obligations, as both PG&E and SDG&E assert, which would contravene the intentions of § 367.

IEP endorses ORA's and EPUC's criteria for determining whether Edison's fuel and fuel transportation costs are recoverable under § 367(c)(2). IEP is specifically concerned with Edison's proposal to recover all of its Canadian gas contract costs, at issue in A.93-05-044 *et al.*, pending Commission review, subject to later adjustment. IEP objects to this treatment because it could prolong the rate freeze, has the potential of allowing Edison the opportunity to over-recover costs and thus price its electricity lower and drive down market prices, and is contrary to the recently filed settlement agreement in A.93-05-044 *et al.* IEP suggests that, pending approval of this settlement, Edison be allowed to recover only 50% of its gas contract costs in the transition cost balancing account, subject to further true-up.

IEP also asserts that Edison's request to recover Wheeler Ridge access charges should be denied. Edison is seeking recovery of charges incurred to transport gas on the SoCalGas system. IEP believes that this contract does not meet the criteria of § 367(c)(2), because the charges Edison pays under this contract are the same as the SoCalGas tariff charges for use of the same Wheeler Ridge facilities. IEP maintains that this contract cannot be determined to be uneconomic, because Edison is paying the equivalent of market rates for Wheeler Ridge access service.

IEP disagrees with Edison's contention that it is impossible to measure the below-market portion of its coal contracts, and disputes Edison's contention that crediting any excess Power Exchange/ISO revenues to the transition cost balancing account is an appropriate remedy. IEP declares that the burden of proof is on Edison to demonstrate that these contracts are uneconomic. IEP recommends that it would be preferable to obtain a measure of the value of these contracts using the price of coal at other sources.

13.10. Discussion

We agree that fuel and fuel transportation costs are plainly delineated in § 367(c) as "going forward costs" of fossil plants, with the exceptions identified in § 367(c)(1) and § 367(c)(2). We do not agree with SDG&E's strained distinction between long-term contracts which Edison enters into and costs which we allocate to SDG&E's UEG customers in the BCAP. On this particular issue, the statutory language is plain and unambiguous: fuel and fuel transportation costs are going forward costs, with the exception of Edison's fuel and fuel transportation costs and operating costs for "particular utility-owned fossil power plants or units at particular times when reactive power/voltage support is not yet procurable at market-based rates." All other fuel costs must be recovered through market prices. We have stated our preference to use market mechanisms to determine transition costs to the extent possible. It is not necessary to provide transition cost treatment for units deemed necessary for reactive power/voltage support by the ISO. As previously discussed, we expect the utilities to negotiate vigorously with the ISO to develop appropriate contracts to cover costs. Certainly, if the ISO does not deem the operation of these units necessary and the utilities shut them down, as SDG&E alleges might occur, there is no reason ratepayers should continue to pay for UEG fixed gas transportation costs while receiving no benefits of the unit's operation. We find such a proposal troubling. We will not guarantee ratepayer recovery for these costs; to do so would not only increase transition costs in a manner that is not in compliance with the law.

We,do not agree with TURN that the fuel contracts signed after the electric restructuring rulemaking was issued should receive additional scrutiny. As established by law, December 20, 1995 is the cut-off date to which we must adhere. Because certain of these contracts are being reviewed for reasonableness in other proceedings (e.g., A.93-05-044 *et al.*), Edison proposes to track these costs in the transition cost balancing account and then adjust them after the fact if any amounts are disallowed by this Commission. We will not allow this treatment. In the noted proceedings, a settlement was filed at this Commission on July 16, 1997. We expect to adopt a decision on this settlement by year-end. Until that time, however, such contract costs should be tracked in a memorandum account and transferred to the transition cost balancing account upon our determination of reasonableness. Again, we disagree with Edison's forced reading of the relevant code sections: it is not that reasonableness must be determined subsequent to transition cost recovery, but that reasonableness must be determined subsequent to execution, which must have occurred no later than December 20, 1995.

Edison's gas purchase credit proposal is needlessly complicated. Fuel costs should be excluded from the transition cost balancing account and recovered from Power Exchange revenues, ISO revenues, and any other market sources, to the extent possible. The same principles hold true for Edison, however, AB 1890 provides for recovery of the uneconomic fixed portion of these fuel and fuel transportation contracts. We prefer to avoid complicated regulatory approaches based on debatable assumptions and to focus on the market. We remain concerned that Edison's proposed treatment may result in ineligible costs being added to the transition cost balancing account, which is not only contrary to our stated policy, but unlawful. Edison's fuel and fuel transportation contracts must first be found reasonable by this Commission. Once that hurdle is cleared, it is the uneconomic fixed costs that may be eligible for transition cost treatment. To the extent Edison cannot receive these costs from market revenues, including the take-or-pay provisions of fuel contracts, Edison may seek transition costs recovery of the demonstrably uneconomic fixed portion of these costs.

Only if market revenues are not sufficient to cover all going forward costs will we allow that portion of the fixed costs which exceeds these revenues to be added to the transition cost balancing account. This market-based approach has the distinct advantage of being relatively simple to implement and intuitively easy to grasp. By using the market to determine the uneconomic fixed costs, we avoid complicated, short-lived mechanisms which only serve to make transition cost recovery more confusing, and more importantly, we ensure that the transition cost recovery process can proceed expeditiously. We agree with ORA that proper accounting is essential so that utilities are required to recover all going forward costs from market revenues, to the extent lawful. We note that under Edison's approach, had its proposed 150 basis point mechanism been adopted, the utility would have greatly benefited because it would have recovered all coal and coal transportation contract costs from the transition cost balancing account before any revenue crediting mechanism was applied, including the 150 basis point earnback.

We discuss PG&E's geothermal contracts in Section 16.

14. Transition Costs and Power Purchase Contracts with QFs

PU Code § 367 affirms the Preferred Policy Decision's finding that the utilities are authorized to collect the ongoing transition costs resulting from the difference between contract prices with QFs and the Power Exchange market clearing price. In addition, transition cost recovery for QF-related costs continues for the duration of the contract and is not limited by the rate freeze period. While we find that such costs are eligible for recovery, we need not approve the forecasts of the costs included in the various utility filings. Transition cost recovery will be based on actual costs incurred compared to the Power Exchange revenues resulting from the market-clearing price.

PG&E recommends including costs related to QF contract litigation, settlements, and administration when comparing contract costs with market revenues. PG&E believes that this is legitimate, because these costs are in effect part of the cost PG&E pays for energy and capacity under these power purchase agreements. PG&E also contends that the Commission has issued contract administration guidelines that require the utilities to aggressively administer these contracts in order to control costs and protect ratepayers. Edison also included these costs in its assessment of QF contract costs.

ORA recommends that reasonableness reviews of the utilities' QF contract management continue to occur annually, but in the annual transition cost proceedings, rather than in the ECAC proceedings. ORA believes that it is essential that the utilities manage these contracts in a prudent manner. SDG&E contends that there is no reason for such a review in the transition cost proceedings, because we have expressed our intent to review this matter for SDG&E on an interim basis in D.97-07-064. SDG&E recommends that the purpose of the annual review regarding both QF and interutility contracts should be limited to an audit of costs, rather than a general reasonableness review, because it believes that this limited review should occur in the distribution PBR proceedings. Enron recommends that we consider requiring the utilities to forecast the annual QF stranded costs and interutility contract costs over the anticipated contract lives.

For PG&E, the auditors question all non-standard contracts, because they were unable to verify that they have been approved by the Commission. The auditors also recommend that any contracts included in the forecast of transition costs and involved in litigation should be considered questionable costs, since resolution of these issues may either increase or decrease projected costs. In addition, the auditors questioned contracts that do not conform with insurance verification requirements and contracts with QFs on probation for not meeting their contractual firm capacity requirements. The auditors presented similar concerns for Edison.

For each of the utilities, the auditors recommend that since transition costs associated with QF contracts depend on actual costs, a verification of these costs will be required, either in the ECAC or the annual transition cost proceedings.

Both AB 1890 and the Preferred Policy Decision state that the actual above-market costs of QF contracts are eligible for transition cost treatment. No forecast of the actual amount is necessary at this time. We will require that the utilities establish placeholders in their final balancing account tariffs to account for these costs when they are incurred. We accept Edison's and PG&E's responses to the audit report, regarding the questioned QF contract costs. No adjustments to these estimated costs are necessary, given that recovery of QF contract costs will be based on amounts actually incurred, rather than the estimated amounts. Costs related to Commission-approved contracts to settle issues associated with the BRPU are also eligible for transition cost treatment, pursuant to § 367(a)(3), although no amount need be forecast at this time. These costs are the focus of other proceedings. The utilities should establish placeholders in the transition cost balancing account to account for these costs, when and if they are approved.

SDG&E is currently under a Generation and Dispatch mechanism, which has eliminated the need for many aspects of traditional ECAC reasonableness reviews, including QF contract terms, because the contracts are standard offers or approved non-standard contracts. This mechanism will remain in place, with certain modifications, until the end of 1997. In D.97-07-064, we determined that reasonableness reviews for QF contract administration were appropriate and should take place "according to existing rate case processing procedures, as those procedures may be modified from time to time." (D.97-07-064, mimeo. at p. 15.) We have previously determined that "[t]he utility will retain its obligation to administer its QF contracts in the best interests of its customers and in a manner that maximizes systemwide benefits and minimizes transition cost accrual." (Preferred Policy Decision, mimeo. at p. 130.)

Consistent with D.97-07-042 and a joint ruling issued on June 25, 1997, by the assigned Commissioner and ALJ, generation PBRs will not be adopted prior to the beginning of the transition period. In the absence of generation PBRs, costs associated with QF and interutility contracts should continue to undergo reasonableness reviews, and these reviews should be undertaken as part of the annual transition cost proceedings, to the extent that such reviews are not eliminated by standard offers and approved contracts. Annual reviews will include a review of contract administration and litigation costs.

In D.96-04-034, which modified D.95-12-051, we provided that PG&E could recover the costs of QF litigation settlements and judgments if prudently incurred, but noted that reasonableness review of these costs was essential:

> "In future reasonableness reviews of settlement and judgment costs, we intend to inspect carefully the sources of the costs. If a settlement or judgment flows from the terms of a QF contract approved by the Commission, we may find that ratepayer support of associated payments is fair and reasonable. On the other hand, if a settlement or judgment is the result of imprudent contract administration by PG&E or in some way compensates a fuel or energy supplier for PG&E actions not approved by the Commission, then we may deny ratepayer support. In particular, judgments in tort actions – which generally exclude contract disputes – should not be recovered from ratepayers." (D.96-04-034, mimeo. at p. 3.)

This same rationale should apply to the litigation costs and QF administration costs for all utilities. We order this verification and showing to occur in the annual transition cost proceeding. This approach will allow us to transition out of the traditional ECAC proceedings. We make no findings at this time regarding the QF shareholder incentive mechanism, nor regarding QF contract restructurings and buyouts, which are being addressed in a separate proceeding.

15. Transition Costs and Interutility Contracts

PG&E, Edison, and SDG&E have various purchased power contracts with other utilities, irrigation districts, or water agencies. Similar to the treatment of QF contracts, both AB 1890 and the Preferred Policy Decision provided for the recovery of the difference between actual payments under those contracts and the cost of comparable energy purchases from the Power Exchange. Again, we emphasize that it is this difference that will be booked to the transition cost balancing account, not the forecast costs. Any revenues received from interutility sales contracts offset the transition costs. These costs will be reviewed in the annual transition cost proceeding.

ORA has agreed that PG&E's discretion in managing its eight purchased power contracts is minimal and therefore recommends that the review of these contract costs should be a simple audit of how the transition cost credit is calculated. ORA encourages SDG&E to renegotiate its two purchased power contracts and that the annual transition cost proceeding should be used to review the administration of these contracts. We concur and order such review to occur in the annual transition cost proceedings.

Edison has entered into 17 interutility power contracts, with prices that may be higher or lower than the market price. Transition costs or credits arising from these contracts are determined by comparing the costs associated with each contract to the corresponding market value of an equivalent amount of energy. In the case of energy exchange, transition costs are determined by comparing Edison's avoided cost and the contract price associated with energy takes and return. The actual transition costs associated with these contracts will be evaluated in the annual transition cost proceeding. Edison has agreed to various audit adjustments of its estimated costs, which relate to reclassifications and revised estimates. Edison objects to ORA's recommendation that the Commission should review purchases to ensure that purchases are maximized when incremental costs are lower than the Power Exchange price and minimized when incremental costs are greater than Power Exchange price. In contrast, Edison recommends that ORA's review process be amended to include verification of benefits associated with interutility purchases, exchanges, or sales made through the Power Exchange. We will review both costs and benefits of such purchases, sales, and exchanges in the annual transition cost proceedings and will review each utility's showing carefully in this regard, consistent with our desire to ensure that transition costs are minimized to the extent possible.

16. Hydroelectric and Geothermal Transition Costs

In addition to its fossil-fired generation assets, PG&E owns both hydroelectric and geothermal generating assets. Edison owns hydroelectric assets, but no geothermal assets. SDG&E owns only fossil assets. Section 367(b) states that for all assets subject to market valuation, such valuation must occur by December 31, 2001. Because the Preferred Policy Decision required that hydroelectric assets and geothermal assets be retained by the utilities (Preferred Policy Decision, mimeo. at p. 135), and AB 1890 was silent on this issue, there has been some dispute as to whether hydroelectric and geothermal assets are indeed subject to § 367(b). Parties have also raised issues regarding the correct rate of return to apply to these assets and whether the depreciation of these assets should be accelerated or not.

The generation PBR proceeding (A.96-07-009 *et al.*) has been modified to defer development of PBR mechanisms and instead will determine 1998 revenue requirements for PG&E's hydroelectric and geothermal generating units and Edison's hydroelectric units. In this transition cost proceeding, we address the following issues associated with hydroelectric and geothermal assets: the net book value as of December 1, 1995, the applicable rate of return, whether depreciation should be accelerated or not, and how to properly track hydroelectric and geothermal costs and revenues in the transition cost balancing account.

Certain issues associated with the ratemaking treatment of hydroelectric plants that are categorized as must-run by FERC and the reasonableness of pumped storage plant costs will be more fully considered in A.96-07-009 *et al.*

16.1. PG&E

PG&E states that it plans to market value all of its non-nuclear generation assets (RT:1281), including its hydroelectric and geothermal facilities. PG&E believes that the reduced rate of return applies only to uneconomic assets. PG&E asserts that when an individual hydroelectric or geothermal asset is identified as having a book value greater than its market value, depreciation on that asset should be accelerated and the rate of return should then be the reduced rate of return. However, PG&E contends that if recovery of the asset is not accelerated, it should continue to earn at the authorized rate of return. PG&E states that it intends to accelerate depreciation of these assets so that book value equals expected market value, and intends to modify the forecast of net salvage used in determining the proper levels of accelerated depreciation as better forecasts become available.

PG&E proposes to debit that the entire hydroelectric and geothermal revenue requirement to the transition cost balancing account. Any ISO or Power Exchange revenues earned by these plants would then be credited to the balancing account. Thus, any net credit would be used to offset other transition costs and any net debit would be recovered through the CTC or other offsets. PG&E recommends establishing the revenue requirement for hydroelectric and geothermal assets in A.96-07-009 *et al.*, but addressing the recovery of those costs in this proceeding.

While PG&E acknowledges that the Preferred Policy Decision provides that surplus revenues from hydroelectric and geothermal assets will be credited to offset transition costs, PG&E contends the Commission has overlooked the possibility that some of these plants could, in the short run, result in a net debit to the transition cost balancing account; e.g., in the event of a dry year. While PG&E expects that these plants as a whole will be economic over the long run, to the extent that timing issues result in a net debit (that is, costs exceed revenues), PG&E asserts that we should allow recovery of these uneconomic costs via the transition cost balancing account.

PG&E explains that until the end of 1992, its hydroelectric relicensing costs were recorded in rate base as these costs were incurred. In D.92-12-057, we determined that these costs should be treated as CWIP, earning an Allowance for Funds Used During Construction (AFUDC) until the new licenses were granted by FERC, at which time the relicensing costs would be transferred to rate base. (47 CPUC2d, 143, 218.) PG&E now requests that we reverse this approach and transfer the December 31, 1997 CWIP balance related to hydroelectric relicensing costs to rate base effective January 1, 1998 for transition cost recovery. PG&E would accept TURN's alternate approach in which the relicensing costs would continue to accrue AFUDC until the time of market valuation and then be recovered in the market valuation process. PG&E explains that the value of a hydroelectric plant is in its license and that the relicensing process is lengthy and subject to certain requirements at precise times. If relicensing efforts were stopped, the value of the hydroelectric facilities would be only the net book value of the historical costs; alternatively, PG&E recommends that if shareholders continue the relicensing efforts, the value of the licensed plant above book value should accrue to shareholders.

16.2. Edison

Edison recommends that hydroelectric generation should earn the full rate of return prior to market valuation. Edison defines costs recoverable through the transition cost balancing account as the difference between the authorized revenue requirement and market revenues. While Edison was unsure initially whether or when it would seek to market value its hydroelectric assets, Edison now agrees that market valuation should occur. (Exhibit 99.)

Edison explicitly states that its agreement to market value its hydroelectric assets is predicated on continuing to earn a full rate of return on those assets until they are market valued. In A.96-07-009 *et al.*, Edison has proposed to derive its hydroelectric revenue requirement from its test year 1995 GRC decision, with certain adjustments.

Edison states that because its development of its hydroelectric revenue requirement is based on 1995 test year levels, it is assuming additional risks in the operation of these assets, which requires a full rate of return, rather than the reduced transition cost rate of return.

Edison states that it does not plan to accelerate recovery of its hydroelectric sunk costs prior to market valuation and argues that there is no reason to reduce the return to reflect the reduced risk associated with accelerated recovery until it occurs.

Edison disputes FEA's and ORA's conclusion that the Preferred Policy Decision limits the transition cost calculation to net credits resulting from hydroelectric assets and believes that such a conclusion would violate § 67(b), which requires the netting of all above-market and below-market assets.

The auditors explain that Edison removed its hydroelectric sunk costs from Edison's Statement of Eligible Transition Costs, which also identified $525.7 million in future hydroelectric PBR costs, as of January , 1998. When the auditors raised concerns regarding double counting, Edison elected to remove the sunk cost amounts. The auditors prefer that Edison remove its hydroelectric PBR costs from its statement of eligible transition costs, because these amounts are based on speculative estimates that cannot be evaluated.

16.3. ORA

Contrary to PG&E and Edison's proposal that any difference between the frozen revenue requirement and market revenues be credited or debited to the transition cost balancing account, ORA asserts that the Preferred Policy Decision provides only for offsets to the transition cost recovery when the hydroelectric Power Exchange revenues exceed the revenue requirement. ORA believes that allowing debits to flow through the transition cost balancing account could make it difficult to limit transition cost recovery of operating costs and suggests that allowing the utilities to recover costs through transition cost recovery could lead to manipulation of the market, because utilities would have an incentive to bid low for their hydroelectric generation.

ORA fears that this bidding behavior could impact the development of the competitive market by preventing market entry, prolonging transition cost recovery, and driving out competitors.

ORA recommends that hydroelectric and geothermal assets should not receive accelerated amortization prior to market valuation because they are likely to have market values exceeding book values. ORA recommends accepting the net book values confirmed by the audit report, provided that capital additions prior to December 1, 1995 are reviewed and audited. Furthermore, ORA recommends that the issue of how differences between an established revenue requirement and market revenues should be tracked in the transition cost balancing account should be determined in A.96-07-009 *et al.*, because that proceeding contains the most comprehensive discussion of ratemaking issues.

ORA agrees that § 367(b) requires market valuation of all assets and recommends that such market valuation occur soon so that any value in excess of net book value can be used effectively to offset transition costs.

ORA generally agrees with PG&E's proposals regarding geothermal assets, but recommends that geothermal steam costs be subject to reasonableness review in either the annual transition cost proceeding or the Revenue Adjustment Proceeding. ORA recommends booking a credit to the transition cost balancing account only if Power Exchange revenues exceed the applicable costs, including non-accelerated depreciation of capital costs for non-must-run units. For must-run units, all costs should be negotiated with the ISO and would not impact transition costs.

16.4. TURN

TURN recommends denying authorization to accelerate the recovery of sunk costs of hydroelectric generation facilities, with two exceptions. TURN asserts that because these assets are likely to have a market value above book value and are likely to generate electricity at costs less than market prices, these assets are the "crown jewels" of the utilities' portfolios. Since hydroelectric assets have a market value above book, there should be no need to accelerate depreciation; indeed, TURN recommends that doing so would violate the principles articulated in D.97-06-60. TURN maintains that market valuation can occur in compliance with § 67(b), without triggering accelerated depreciation.

TURN recommends that pumped storage facilities, which are likely to have book values in excess of market values, and other individual plants sold at less than book value should be allowed transition cost treatment. TURN recommends that past hydroelectric relicensing costs should be recovered consistent with the ratemaking treatment afforded the underlying plant. If the hydroelectric plant is market valued during the transition period, the relicensing costs should be recovered as an offset to the market value. If the Commission determines that these assets should continue to be owned by the utilities, TURN states that it could support Edison's proposal to accrue AFUDC on these costs and recover them in the PBR mechanism.[22] TURN recommends that no accelerated recovery be afforded past relicensing costs with the exception of those plants already sold or those that are sold before 2001. TURN further recommends that hydroelectric and geothermal assets should earn the lower rate of return if market valuation is proposed for these assets. The full rate of return should apply if the utility holds them in regulated service and market values them on an annual basis through credits against other rate components after 2001.

16.5. FEA

FEA recommends that to the extent hydroelectric and geothermal assets are retained by the utilities, only the surplus of hydroelectric revenues over associated costs should be permitted to reduce transition costs; any deficit should not be permitted to increase transition costs. FEA supports the auditors' proposed adjustment to remove Edison's $525.7 million in hydroelectric PBR costs from the transition cost balancing account.

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[22] In its July 1, 1997 compliance filing in A.96-07-009 *et al.*, Edison states that it will commit to recover these costs out of the frozen level of currently authorized revenues and that any hydroelectric relicensing costs should be recovered through the market valuation process.

16.6. CIU

CIU contends that market valuation is required for all facilities to calculate the complete transition cost formula and is not a matter of utility choice. CIU agrees that accelerated depreciation is not appropriate for hydroelectric and geothermal assets prior to market valuation. CIU recommends waiting until after the new competitive market begins operation to consider the market valuation of hydroelectric assets, although CIU recognizes that valuation before the end of the transition period is important.

16.7. Discussion

We agree that careful treatment regarding the hydroelectric and geothermal assets is in order. We accept the auditors' determination of the net book value as of December 31, 1995 as the starting point for determining whether assets will ultimately be economic or uneconomic.

AB 1890 is silent regarding the treatment of these particular categories of assets, although market valuation is required "for those assets subject to valuation." in § 367(b). Section 367 requires that we determine the cost categories that may become uneconomic as a result of the competitive generation market. While we are not convinced that hydroelectric and geothermal assets, with the possible exception of pumped storage facilities, are likely to be uneconomic, we believe that ratepayers will benefit by ensuring that these assets earn the reduced rate of return and that excess revenues are credited to offset transition costs. We find that it is appropriate to include the amortization of any current costs of hydroelectric and geothermal assets in the transition cost balancing account. PG&E will recover geothermal steam contract costs in the revenue requirements set in A.96-07-009 et al.

A separate proceeding is underway to determine the revenue requirements associated with these assets. This revenue requirement will be developed based on a cost-of-service approach, and will include amounts to offset fixed costs, nonfuel variable costs, depreciation, taxes, and a return on investment. Calculations of the revenue requirement should begin with the net book value adopted in these proceedings.

Revenues earned through the Power Exchange and ISO for hydroelectric and geothermal assets should be tracked in a memorandum account and compared to the revenue requirements established for these assets in A.96-07-009 *et al.* Market revenues in excess of revenue requirements should be credited to the transition cost balancing account on an annual basis. Similar to the memorandum accounts established for the fossil must-run and non-must-run plants, any excess revenues accruing in a particular month will earn the reduced transition cost rate of return, rather than the commercial paper rate. Applying the reduced rate of return to these revenues is appropriate because this higher interest rate compensates ratepayers for carrying costs associated with transition costs that would otherwise have been reduced through monthly postings. No interest rate or rate of return will be applied to any debit balances in that memorandum account. This approach is consistent with ensuring that transition cost recovery occurs as expeditiously as possible. Because these assets are afforded transition cost treatment, the reduced rate of return should be earned.

Pumped storage plants are also likely to be uneconomic in the new competitive generation market. We will therefore allow recovery of costs associated with pumped storage assets in the transition cost balancing account; however, complete ratemaking determinations cannot be made pending the outcome of the treatment of must-run and non-must-run hydroelectric plants, including pumped storage assets, in A.96-07-009 *et al.* Once we have issued our decision in that proceeding, we will allow PG&E and Edison to modify their balancing account tariffs to more fully delineate the balancing account treatment of pumped storage facilities.

Section 367(b) requires basing the determination of uneconomic costs on a comparison of market value to book value for utility-owned generation assets. The Legislature has provided explicit affirmation of the benefits of competition, as well as directions that transition cost recovery should be orderly, expeditious and that the transition from regulated status to unregulated status must occur through means of Commission-approved market valuations. We conclude that hydroelectric and geothermal assets are subject to market valuation and that we must approve all market valuation mechanisms, including the timing of these mechanisms. Market valuation must occur well before 2001 so that the netting process can occur as required by § 367(b).

Past relicensing costs should be accounted for in market valuation process, as PG&E, Edison, and TURN now agree. These amounts will continue to be recorded in CWIP and accrue AFUDC. This approach is consistent with our preference to use market mechanisms to determine transition cost recovery.

17. Regulatory Assets, Liabilities and Transition Obligations and Balancing Accounts

In the Preferred Policy Decision, the Commission recognized that regulatory assets and liabilities have arisen from various deferred costs and outstanding balancing account balances which each utility has accrued under traditional cost-of-service regulation. Regulatory assets results in the ratepayers owing money to the utility; regulatory liabilities result in the utility owing money to ratepayers. Regulatory assets and liabilities are defined in the FERC Uniform System of Accounts as follows:

> "Regulatory Assets and Liabilities are assets and liabilities that result from rate actions of regulatory agencies. Regulatory assets and liabilities arise from specific revenues, expenses, gains, or losses that would have been included in net income determination in one period under the general requirements of the Uniform system of Accounts but for it being probable:
>
> "A. that such items will be included in a different period(s) for purposes of developing the rates the utility is authorized to charge for its utility services; or
>
> "B. in the case of regulatory liabilities, that refunds to customers, not provided for in other accounts will be required." (18 CFR, Part 101, p. 259, April 1, 1996.)

As we explained in Section 6.5, we find that both regulatory obligations and contractual obligations are eligible for transition cost recovery, in conformance with § 367. However, we will review each claim for transition cost recovery in this category to determine whether such assets and obligations are generation-related, unavoidable, and uneconomic.

In D.92-12-015, we accepted the following definition in terms of post-retirement benefits other than pensions (PBOPs) and the applicability of Statement of Financial Account Standards (SFAS) 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 incurred cost rather than to provide for expected levels of similar future costs." (46 CPUC2d 499, 536.)

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

It is useful to put the ratemaking approach to regulatory assets in perspective as we proceed. First, it is important to distinguish between "accrual" accounting and the "pay as you go" method. Accrual accounting occurs when the utility recognizes the costs of benefits as they are earned or attributed to an employee, as services are provided. For financial reporting purposes, utilities account for PBOPS, pensions, workers' compensation, and long-term disability benefits on an accrual basis (i.e., an actuary determines the total expected obligation for benefits owned to employees and the utility recognizes a portion of the accrual each year as the employee continues to provide service). In contrast, under "pay as you go" accounting, a utility recognizes an employee benefit cost when it actually pays such a benefit to the employee.

ORA explains that there is no disagreement regarding financial reporting of regulatory assets, which is a management decision. ORA states that this Commission must determine whether these costs should be treated similarly for ratemaking purposes. In general, ORA believes that benefit obligations associated with future generation-related activities of the utilities after divestiture can be funded from future market revenues. In other words, ORA believes that these obligations should be recoverable through pre-1998 ratepayer funding of accruals towards active employees, because these obligations will be eliminated or decreased due to divestiture.

ORA suggests that several issues must be resolved before we determine that particular regulatory assets are eligible for transition cost recovery. ORA believes that the record is insufficient to answer these key questions and recommends workshops to determine: 1) whether regulatory assets should be eligible for recovery at all, i.e., by AB 1890 criteria or by previous Commission decision; 2) when it is appropriate for the utilities to establish a regulatory asset; 3) whether particular regulatory assets are related to historic operations or whether these assets include going forward costs; 4) whether such costs could be mitigated in some way and whether transition cost recovery may encroach upon that mitigation; and 5) if found eligible, what portion of these regulatory assets should be subject to transition cost recovery.

As previously discussed, EPUC and CIU contend that regulatory assets associated with fossil plants are not eligible for recovery. This narrow approach is inconsistent with the law, and we find that generation-related regulatory assets are eligible for recovery as a cost category. We will consider the disputed issues of the various regulatory assets in question. As a threshold matter, we are addressing the eligibility of various employee benefits for recovery in the transition cost balancing account that have been earned or attributed to employee service rendered <u>prior</u> to January 1, 1998 for generation employees. <u>After</u> January 1, 1998, these costs must be included in current operating costs and recovered from market revenues.

In general, ORA also recommends denying regulatory assets for transition cost recovery. ORA states that this is true because either the utilities did not file to have past benefit obligations recovered in future time periods or the utilities are not in compliance with D.92-12-015, in terms of PBOPs. ORA's position is that divestiture and subsequent termination of maintenance contracts will lead to reduced payroll expenses and lower PBOP expenses than were assumed in the actuarial calculations. PG&E asserts that amortization should begin on January 1, 1998, a position which PG&E states is consistent with the requirements of D.97-06-060. ORA also recommends establishing accounting safeguards to prohibit non-generation operations from subsidizing generation and the diversion of ratepayer funding of employee benefits to non-pension and benefits usages.

ORA proposes that all other regulatory assets be eligible for transition cost recovery, with the following conditions. Regulatory assets related to deferred taxes should be treated according to the provisions of the joint recommendation contained in Exhibit 101. In addition, ORA recommends that certain PG&E ECAC balancing account amounts related to disallowances should be refunded to customers, rather than being credited to the transition cost balancing account.

17.1. Workers' Compensation

PG&E proposes to recover the workers' compensation regulatory asset in the transition cost balancing account, based on the December 31, 1997 balance, to be amortized over the 48-month transition period. PG&E explains that if an employee has a claim under workers' compensation, then PG&E is legally obligated to provide the required level of benefits. PG&E believes that the proper rate of return to apply to this balance is PG&E's discount rate at December 31, 1997. Workers' compensation costs are recognized on an accrual basis for financial reporting purposes, but are recovered on a pay-as-you-go basis for ratemaking. Assuming no new entrants are afforded workers' compensation benefits, the differences resulting from these two accounting methods would zero out over time under traditional ratemaking, because the regulatory asset is reduced as rates are received each year. PG&E contends that there is a reasonable expectation that it would recover all of its workers' compensation accruals in rates over time. PG&E plans to avoid any double counting, an issue that concerns TURN, by reducing the current cost revenue requirement for any costs provided by recovery of this regulatory asset. These costs would be subject to review in the annual transition cost proceeding.

Edison has identified a generic regulatory asset for post-employment benefits, including workers' compensation and long-term disability. This proposal is discussed in Section 17.2, Long-term Disability.

ORA states that because PG&E funds workers' compensation obligations on a pay-as-you-go basis, PG&E is collecting current costs through rates; i.e., the fact that PG&E's workers' compensation obligations are recognized on its financial statements in accordance with SFAS 112 (Employers Accounting for Postemployment benefits) is irrelevant. ORA concurs with TURN's objection to transition cost recovery of these costs because it is impossible to distinguish between pre-1998 and post-1998 liabilities.

TURN contends that this regulatory asset is not eligible for transition cost recovery, because PG&E has not borne its burden of proving the appropriate level of the costs to be recovered, has not demonstrated that going forward costs are excluded from recovery, and has not established that double counting will not occur. TURN recommends that if recovery is allowed, no rate of return should apply.

17.1.1. Discussion

In D.95-12-055, we determined that PG&E's requested increase in revenue requirements for workers' compensation and other casualty payments would be mitigated to some extent by employee reductions, and we reduced the adopted revenue requirements. These costs are recovered on a pay-as-you go basis; therefore, the rates include costs that would also have been included in the actuarial calculation for post-1998 obligations of the workers' compensation regulatory asset. This is quite different from the methodology PG&E uses to address its long-term disability obligation. In this case, PG&E has not adequately distinguished costs which represent past obligations from costs which represent future obligations. The Commission has never established a regulatory asset for workers' compensation obligations. Because rates are frozen throughout the transition period, we expect that the forecasted revenue requirement will be adequate to cover PG&E's generation-related workers' compensation obligation related to pre-1998 claims. There is significant potential for double recovery, as well as a mingling of pre-1998 and post-1998 costs that is inappropriate in the new generation market; therefore, we will exclude PG&E's workers' compensation regulatory asset from transition cost recovery at this time.

PG&E may demonstrate in the annual transition cost proceeding that its actual payments in 1996 and 1997 for workers' compensation claims exceed what had been previously approved in rates for generation employees.

17.2. Long-term Disability

PG&E and Edison propose to recover the long-term disability regulatory asset in the transition cost balancing account, based on the December 31, 1997 balance, to be amortized over the 48-month transition period. Again, PG&E explains that if an employee has a legitimate long-term disability claim, the utility is legally obligated to provide the required benefits. Long-term disability costs are recognized on an accrual basis for financial reporting purposes and are recovered on a funding/accrual basis for ratemaking. Prior to its 1996 GRC, PG&E collected these expenses on a pay-as-you-go basis. In D.95-12-055, we authorized a $17 million increase in PG&E's revenue requirements to fund the accounting change for long-term disability obligations from a cash basis to an accrual basis.

PG&E contends that authorized rate recovery for long-term disability costs compared to projected levels of future expenses are not equal and a regulatory asset has been created to account for these differences. Under traditional ratemaking, PG&E expected that it would eventually recover these generation-related costs recorded on an accrual basis prior to January 1, 1998 relating to past employee service. PG&E believes that the proper rate of return to apply to this balance is PG&E's discount rate at December 31, 1997. PG&E recommends that it is the unfunded obligation, not the initial unamortized obligation, as of December 31, 1997, which should be amortized in the transition cost balancing account, because the long-term disability obligation is revalued each year.

ORA believes that PG&E's request should be denied, because this amount reflects the difference between what was authorized in D.95-12-055 and what the utilities have booked or will book in the future. ORA believes that this obligation is applies to active employees and will be eliminated as divestiture occurs. The past funding of active employees who will leave the utilities' employment should provide sufficient funding for obligations resulting from claims of remaining employees.

TURN recommends recovering PG&E's long-term disability obligation as a transition cost, because TURN agrees with PG&E's proposed treatment of this obligation (i.e., establish a trust fund for long-term disability costs, set up an initial obligation, and to change to the accrual basis for cost recovery). TURN does not agree that the long-term disability obligation should be revalued each year, and states that this amount must be fixed and amortized as of the time the obligation was identified to prevent any inappropriate inclusion of going-forward costs in the regulatory asset collected through transition cost recovery. TURN recommends that the initial obligation should be that established in PG&E's 1996 GRC. TURN believes that there should be no rate of return applied to this asset and that there should be a rate base offset with normalization of deferred taxes, if these costs are not immediately deposited in a trust.

Edison and TURN now agree on Edison's approach to post-employment benefits and have agreed to the following criteria: 1) Edison requests recovery of costs associated with post-employment benefits for liability associated with claims made pre-1998 and plans to amortize the amount as of December 31, 1997 over the 48-month amortization period as established in D.97-06-060; 2) Edison is not requesting a rate of return on regulatory assets associated with post-employment benefits; and 3) the regulatory asset associated with post-employment benefits associated with employees of non-must-run fossil stations made subsequent to December 31, 1997 will be considered going forward costs rather than unavoidable costs and is proposed to be reflected in the operation of the 150 basis point incentive computation.

17.2.1. Discussion

Because we have approved accrual accounting treatment for this obligation and we can establish a cut-off point for going forward costs, the long-term disability obligation is eligible for transition cost recovery. For Edison, we adopt the post-employment benefits ratemaking treatment jointly proposed by Edison and TURN: 1) benefits will follow labor dollars and the rate recovery depends on which business unit the labor is associated with, i.e., for generation-related nuclear obligations, recovery will occur through SONGS ICIP and Palo Verde incremental cost mechanisms; for fossil assets, recovery will occur through the transition cost balancing account regulatory asset subaccount. For hydroelectric assets, TURN and Edison have jointly proposed that recovery occur through the hydroelectric PBR. The generation PBR has been deferred; however, the Commission is establishing a revenue requirement for hydroelectric assets. Transition cost recovery is authorized only for the regulatory asset associated with claims made prior to 1998. Edison shall not use the pay-as-you-go methodology and shall recover the amount recorded as of December 31, 1997, which will then be amortized ratably over the 48-month transition period. No rate of return will be applied to this regulatory asset subaccount, nor will any of the regulatory asset balances earn any interest, consistent with our prior ratemaking approach to these assets.

In D.95-12-055, we adopted the Division of Ratepayer Advocates' (ORA's predecessor) recommendations regarding long-term disability obligations. Prior to collecting any funds for this purpose, PG&E was required to establish a trust which provides that PG&E may not divert any trust assets to uses other than post-employment benefits. In that decision, we also determined that "[u]ltimately, PG&E shall refund any amounts included in rates that are not contributed to the fund." (D.95-12-055, mimeo. at p. 29.) PG&E's post-employment benefits should be accounted for similarly to Edison's. The initial obligation as established in the 1996 GRC decision should be amortized over the 48-month transition period. This amount equates to the level established by actuarial assumptions as reflected in current rates and is an approach consistent with § 367. We see no need to revalue this amount, which has the potential of increasing this obligation. No rate of return or interest shall be applied to this regulatory asset subaccount. These costs shall be subject to review in the annual transition cost proceedings.

17.3. *Post-Retirement Benefits Other than Pensions (PBOPs) and PBOPs Transition Obligation*

The PBOP regulatory asset represents estimated costs for medical and life insurance benefits accrued since 1993, which are not yet recovered in rates. PG&E and SDG&E propose to recover the PBOP regulatory asset in the transition cost balancing account, based on the December 31, 1997 balance, to be amortized over the 48-month transition period. SDG&E explains that this asset represents costs obligated prior to December 20, 1995, all of which were approved for recovery in SDG&E's 1993 GRC. PG&E recommends that amortization of the amount as of December 31, 1997 should be spread over the four-year transition period and recommends that the proper rate of return to apply to the unamortized balance is PG&E's discount rate at December 31, 1997.

The PBOP transition obligation represents the cost of medical and life insurance benefits attributed to employee service which occurred prior to 1993. The transition obligation was adopted in D.95-12-015 and the utilities were authorized to amortize its balance over 20 years. This amortization amount has been included in the revenue requirements for each utility. There will be 15 years left on the transition obligation amortization schedule as of January 1, 1998. PG&E, Edison, and SDG&E propose that the balance in PBOP Transition Obligations as of January 1, 1998 (calculated according to the Commission-approved 20 year amortization schedule) be recovered in the transition cost balancing account over the 48-month transition period.

Edison points out that if the amount collected in rates and funded is not completely tax-deductible, it would have to be grossed-up for income taxes. Edison has estimated the amount attributable to non-nuclear generation by calculating the ratio of non-nuclear to total 1995 dollars and then applying that ratio to the actuarially determined transition benefit obligation as of 1995; however, Edison explain that amounts actually recovered will vary. D.97-06-060 requires that regulatory assets be amortized over the 48-month transition period, and because § 367(d) requires that transition costs be adjusted throughout the transition period, the transition benefit obligation must be updated annually.

Consistent with its overall recommendations on these regulatory assets, ORA insists that PBOPs regulatory assets and transition obligations are not eligible for transition cost recovery. ORA continues to recommend that the obligation associated with this benefit will be reduced or eliminated as the work force is reduced; hence, the past funding of active employees who leave the utility's employment should provide sufficient funding for future obligations of remaining employees. ORA is also concerned that the utilities would receive funding in excess of what can be contributed to the trusts on a tax-deductible basis.

TURN recommends that a uniform policy be established for PBOPs for all three utilities: 1) all eligible PBOP amounts must be collected in transition costs by the end of 2001; 2) any uncollected PBOP amounts or unamortized PBOP transition obligation should not earn interest, consistent with the provisions of D.92-12-015; 3) any PBOP amounts not deposited in the trust fund should be a rate base offset net of deferred taxes; and 4) if any utility reduces its post-retirement benefits in the future, which in turn reduces the actuarial basis of its PBOP transition obligation, any excess dollars collected for generation should be refunded to ratepayers.

TURN recommends rejecting PG&E's request to earn interest on PBOP costs and Edison's request to collect generation-related PBOPs after 2001. TURN states that PG&E has accrued a regulatory asset related to PBOPs because of a difference in applying the correct discount rate. TURN explains that PG&E used a different discount rate for evaluating its PBOPs obligation than the discount rate of 9% adopted in D.95-12-055. TURN believes that no rate of return should be applied to this asset and that there should be a rate base offset with normalization of deferred taxes if these costs are not immediately deposited in a trust.

TURN recommends that the utilities should be eligible to collect the generation-related PBOPs transition obligation as of December 31, 1997, because these transition obligations were incurred as a result of past service by generation employees. TURN maintains that to the extent that Edison wants transition cost recovery for PBOPs, it should be required to recover its generation-related transition obligation by the end of the transition period and should not be allowed to defer generation-related transition costs for recovery in non-generation rates, which TURN asserts is prohibited by § 368(a). TURN agrees with the amortization approach, but recommends that no rate of return be applied, consistent with D.92-12-015. TURN also recommends a rate base offset, which will produce credits to the transition cost balancing account, if this obligation is not immediately deposited in the trust.

CIU thinks that Edison should not claim PBOPs related to Mohave employees, because this obligation is related to the coal mine's employees, rather than Edison's employees.

17.3.1. Discussion

It is helpful to understand the historical framework underlying ratemaking treatment of PBOPs and the PBOP transition obligation. The Financial Accounting Standards Board (FASB) has defined PBOPs as those benefits other than pensions that employees would receive upon their retirement from the active work force, including medical and dental care, life insurance, and legal services. The Commission opened I.90-07-037 in 1990 to determine the ratemaking impact of changing accounting for PBOPs from a cash to an accrual basis and to address the ramifications of SFAS 106. In D.91-07-006, we determined that the change from cash to accrual accounting for these obligations was reasonable and that the utilities should pre-fund PBOPs with tax-deductible trust plans prior to January 1993, the effective date of SFAS 106. We also established safeguards for these trusts. In D.92-12-015, we determined that PBOP costs consist of a service cost, an interest cost, the actual return on plant assets, and the amortization of the transition benefit obligation. We also found that the substantial increase in PBOP costs under accrual accounting was due primarily to the transition benefit obligation, which recognizes all PBOP benefit obligations at January 1, 1993 less any plan assets at that date. We determined that the transition benefit obligation should be amortized over 20 years, which would mitigate inter-generational inequities, and that water, energy, and telecommunication utilities should "recover their PBOP costs in rates to the extent that they are able to make tax-deductible contributions to tax-deductible plans" and should also establish a regulatory asset for ratemaking purposes which would reflect the annual differences between PBOP expense determined in accordance with SFAS 106 and the tax-deductible contributions recovered in rates. The decision also established that the PBOP regulatory assets would not be a component of rate base and therefore would not earn a rate of return.

We are not persuaded by ORA's arguments. These regulatory assets have been established with our authorization and fit the criteria established by § 367. The PBOP regulatory assets, including the PBOP transition obligation, are eligible for recovery through the transition cost balancing accounts and should be amortized ratably over the transition period, with no recovery beyond 2001. These amounts should be amortized based on the December 31, 1997 estimates, which represent actuarial determinations of past obligations, with no rate of return or interest applied to the unamortized balances. If post-retirement benefit plans are modified to reduce benefits during the transition period, which then reduces the actuarial basis of the transition obligations, these true-ups should be accounted for as credits to the transition cost balancing account. We agree with Edison that such adjustments should be made during the transition period only. For PG&E, it is reasonable to apply the discount rate of 9% adopted in D.95-12-055. If PG&E believes this discount rate was adopted in error, PG&E must file a petition for modification in the relevant proceeding. These accelerated amounts are to be placed in the appropriate trust funds for each utility; to the extent they are not so deposited, these amounts will be treated as a rate base offset with a corresponding credit to the transition cost balancing account.

Edison acknowledges that it does not yet have any obligations related to the Mohave coal mine employees for PBOP expenses. We will exclude these amounts from transition cost recovery at this time. We will not allow a tax gross-up to the extent these contributions to the trust are not tax-deductible. Instead, we adopt TURN's recommendation not to be contributed these dollars to the trusts until they are tax-deductible. Any money which is collected but not yet contributed then becomes a rate base offset, which is reduced by deferred taxes associated with the asset for the taxes due when the money is collected. This approach will address necessary tax requirements, but avoids imposing an additional cost on the ratepayers. This is an example of an approach which aligns both shareholders and ratepayers interests.

17.4. Pensions

Pensions can give rise to either a regulatory asset or liability and to a transition benefit obligation, similar to PBOPs. The utilities state that a regulatory asset or liability can arise with respect to pensions because of different methods for calculating the pension expense for ratemaking purposes and financial reporting purposes. SFAS 87 addresses accounting for pensions for financial reporting purposes. In D.88-03-072, we declined to adopt SFAS 87 for ratemaking purposes. This decision applied to telephone carriers, but has been broadly applied to energy utilities (e.g., D.89-12-057; D.91-12-076). In D.88-03-072, we determined that the aggregate cost method of accounting for pension expense was appropriate for ratemaking purposes. Under this method, the estimated total benefit due at retirement is forecasted and an amount is calculated to provide this benefit, discounted to net present value and spread over future years on a levelized basis. SFAS 87 proposed a unit credit method, based on the yearly pension costs of an employee (i.e., lower in the beginning of an employee's years of service and rising as the employee ages). We found that if the yearly benefits approach were adopted for pension expense, it would be inconsistent with other ratemaking policies and would result in a mismatch of the amount expensed for ratemaking purposes and the amount actually required to be contributed to the pension funds.

PG&E asserts that the regulatory asset or liability arises from the SFAS 87, which require a change from the cash basis to the accrual basis of accounting and allowed the transition adjustments to be amortized over several years. PG&E explains that based on accrual accounting, rather than cash accounting, a regulatory liability related to pensions is expected as of January 1, 1998, which it proposes to credit to the transition cost balancing account. PG&E observes that over time there would be no difference between accounting by SFAS 87 or by the aggregate cost method. PG&E maintains that because of electric restructuring, these differences cannot be evened out and these costs become equivalent to sunk costs. PG&E states that full recovery of the pension transition obligation (to address the change from cash basis to accrual basis) will not occur by the end of the restructuring transition period and this amount should therefore be recovered as a sunk cost. PG&E proposes to net the transition obligation with the regulatory liability and to credit the transition cost balancing account for this amount.

Edison proposes that either the debit or credit balance as of January 1, 1998 should flow through the transition cost balancing account over the 48-month amortization period. Edison explains that the difference between book and ratemaking pension expense created a regulatory liability of $1.8 million by year-end 1995, but Edison did not include this amount as an offset to transition costs because it expected that this amount would either zero out or revert to a *de minimus* regulatory asset balance by year-end 1997.

ORA believes that pensions and benefit obligations differ from other assets for which the utilities seek transition cost recovery, because rate base items have been reviewed for reasonableness, which ORA asserts is not the case for these regulatory assets. ORA maintains that there is not a straightforward relationship between past Commission decisions and particular amounts requested for transition cost recovery. ORA recommends that the generation-related obligations to retirees which remain with the utility can be funded without transition cost recovery and that many of these obligations will be eliminated with divestiture. ORA explains that pension obligations are governed under various sections of the Internal Revenue Code and the Employee Retiree Income Security Act, which require pension benefits to be funded as earned and to vest with the individual employee. Furthermore, because ratemaking is based on the tax-deductible contribution amounts, ORA contends that there is no basis for extending recovery beyond what has already been funded and the employees have earned.

TURN demonstrated that this liability has grown from $1.8 million to $4.7 million by year-end 1996. Edison agrees with TURN that any regulatory liability related to pension expense should be credited to the transition cost balancing account, but only if it receives symmetrical treatment for any similar debit balances. Subsequent to its rebuttal testimony, Edison discovered that this calculation had failed to account for the pension transition obligation, which is estimated to equal $5.6 million for non-nuclear generation pension expense. Edison proposes that this amount be netted with the regulatory liability and the difference as of December 31, 1997 (either liability or asset) should be amortized over the transition period. Edison thus proposes that the fossil-related pension transition obligation balance left to be amortized as of January 1, 1998 (calculated under the Commission-approved 17-year amortization schedule) should be recovered through transition costs over the 48-month period. SDG&E agrees that the regulatory asset should be amortized over the 48-month period.

For PG&E and Edison, TURN recommends that if the regulatory asset resulting from the transition obligation is offset by larger regulatory liabilities resulting from ratemaking pension costs exceeding financial reporting pension costs, the net regulatory liability balance as of January 1, 1998 should be credited to reduce transition costs. TURN assumes that any net regulatory asset is a result of amortizing the transition obligation and TURN recommends that this asset should be reduced to zero for transition cost recovery purposes. TURN asserts that the utilities' pension funds have significant amounts of excess reserves relative to the amounts needed to pay the claims of future retirees, even after repaying the transition obligation; therefore, no additional recovery should be available through transition costs. TURN explains that PG&E has been able to pay this transition obligation at no expense to the ratepayers because the pension fund has been a source of income to PG&E. TURN expects that this scenario will continue, at least through the transition period.

TURN recommends establishing the following safeguards, if these costs are included in transition cost recovery: 1) if PG&E's pension expense in any year is less than the amount of the aggregate annual transition obligation, PG&E should be required to reduce its transition costs by the amount of the generation-related annual transition obligation which is paid by income generated internally by the pension fund and 2) PG&E's request for interest should be denied because PG&E has invested no money to create this regulatory asset. Similar to PBOPs, this regulatory asset is merely an accounting convention; therefore, no interest should be earned, moreover, PG&E does not earn interest on this amortization under current ratemaking procedures.

For SDG&E, TURN recommends disallowing the regulatory asset balance. TURN observes that for ratemaking purposes, pension payments are recognized to the extent that they are tax-deductible under Federal rules, while expenses are calculated on an actuarial basis. Contributions are deductible for tax purposes only if money actually needs to be contributed to the pension funds to ensure that adequate funds are available to pay benefits. Because the actuarial definitions of adequate funding are often more conservative than tax requirements, the difference between the pension cost for book purposes and ratemaking purposes (based on the maximum tax-deductible cash contribution to the fund) has increased. Pension funds have also had large increases in the value of their assets, as the stock market has risen in recent years. TURN explains that while these facts may create larger regulatory assets, they should not lead to corresponding increases in transition cost recovery.

17.4.1. Discussion

We are troubled by the utilities' requests for transition cost recovery for regulatory assets associated with pension expenses and the pension transition obligation. We have clearly never authorized a regulatory asset associated with the difference in accounting required by SFAS 87 and that adopted for ratemaking purposes. The pension transition obligation is not a recorded regulatory asset, but is amortized in rates, and acknowledged in footnotes to the financial statements, as is the PBOP transition obligation. (RT: 1071; 1891). The unrecognized pension transition obligation was established in the past to correct prior pension under-funding through equal annual payments, without interest. PG&E, Edison, and TURN essentially agree on the methodology, if a net regulatory liability exists; i.e., the regulatory asset consisting of the pension transition obligation should be offset by the regulatory liabilities stemming from the amount by which ratemaking pension expense has exceeded financial reporting pension expense. If this calculation, as of January 1, 1998, results in a net regulatory liability, this amount should be credited to the transition cost balancing account (i.e., to reduce transition cost recovery). This would have the effect of using the existing regulatory liability to fund the existing transition obligation. We prefer this approach, rather than debiting the transition obligation regulatory asset through the transition cost balancing account, for the following reasons.

TURN demonstrated that the pensions are over-funded and no tax-deductible contributions have been made recently, nor are they expected in the near term. In D.95-12-055, we adopted PG&E's proposal to set pension costs according to the benefits accruing to current employees, but acknowledged that this funding level could result in contributions that are too high if PG&E reduces its work force. We determined that we would review these assumptions when PG&E has a general review of its rates, or PG&E should file an advice letter no later than December 31, 1999 proposing ratepayer refunds, if required. Absent the amortization of the pension transition obligation, both PG&E and Edison acknowledge that it is likely that a regulatory liability will result from the difference between ratemaking and financial reporting, i.e., tax-deductible contributions are limited because of over-funding. It is reasonable to require PG&E and Edison to offset this accounting obligation with the over-funded amounts, rather than increasing transition costs unnecessarily.

SDG&E's claim to $5.3 million stems from the difference in ratemaking and financial reporting, but does not appear to be related to its transition obligation. SDG&E does not agree that its pension fund is over-funded. We will apply the same treatment at this time, but will allow SDG&E to come forward in the annual transition cost proceeding to establish that the pension fund is under-funded, the derivation of the under-funding, if any, the interaction with its PBR, and why these amounts are eligible for transition cost recovery.

17.5. Environmental Compliance

PG&E explains that its Hazardous Substance Mechanism (HSM) balancing account and the environmental compliance regulatory asset work together in that the HSM represents costs already incurred for hazardous waste clean-up activities for environmental cleanup of specific sites, net of insurance proceeds or other recoveries.

The environmental compliance regulatory asset is a forecast of costs to be incurred for the same activities included in the HSM. These costs are in addition to those recovered in rates for decommissioning. These activities do not include clean-up activities associated with generating plant.[23] The sites covered by the HSM are manufactured gas plants or off-site disposal facilities. Thus, the environmental compliance regulatory asset reflects costs that PG&E is likely to incur in the future; recovery of such costs typically occurs in the HSM. PG&E wants to ensure that it has a fair opportunity to recover future costs associated with already-incurred environmental liabilities.

Ratepayers bear 90% of these costs; shareholders, 10%. The corresponding regulatory asset is the Environmental Compliance Mechanism (ECM), which reflects 90% of the costs PG&E forecasts to be incurred to complete PG&E's responsibility to clean up the sites covered by the HSM. The HSM allocates 70% of these costs to gas ratepayers and 30% to electric ratepayers. In the current ratemaking regime, that 30% would have been collected through bundled electric rates. PG&E now proposes to recover the generation portion through transition cost recovery.

PG&E has allocated 28% of the ECM regulatory asset to transition cost recovery. PG&E asserts that this calculation results in transition cost recovery for less than 10% of its overall estimate of the cleanup costs reflected in the ECM. PG&E explains that the remainder of the ratepayer obligations represented by the ECM (i.e., costs related to transmission and distribution) will continue to be collected through the HSM based on actual costs.

Edison records projected environmental remediation costs as regulatory assets if it is probable both that the obligation to expend funds has attached and that these costs would be recovered in rates. Edison explains that this approach is required by SFAS 105, Accounting for Contingencies, which requires that an estimated loss from

[23] PG&E explains in Exhibit 37 that "because environmental clean-up was part of the estimates of non-nuclear decommissioning in the GRC and because of the normal workings within rate base of cost of removal in the GRC process, recovery of environmental decommissioning through the HSM was not necessary." (Exhibit 37, p. 2-3.)

a contingency should be accrued if it is probable that a liability has occurred and the amount of the loss can be reasonably estimated. Edison records its projected environmental remediation costs as regulatory assets because, as they are paid out over time, it is assumed that they will be recovered in rates, as has occurred in the past. While Edison states that is was not planning to estimate any recovery of these costs through the transition cost balancing account, since D.97-06-060 requires amortization of its generation-related regulatory assets by 2001, Edison is now requesting that this amortization be based on the estimated 1998 balance, which it asserts is also PG&E's position. The auditors question the entire estimated amount of $9.6 million, stating that there is no specific authorization for recovery of these costs in AB 1890. Edison maintains that such costs are properly recorded and that recording costs as a regulatory asset does not require that the Commission pre-approve that classification. Edison maintains that whether a cost is recorded as a regulatory asset is based on criteria set forth in FASB 71. Edison disputes FEA's contention that this specific regulatory asset had not been identified as being collected in rates as of December 20, 1995, and contends that this is a category of costs clearly covered by § 367.

SDG&E has no environmental compliance costs for which it seeks transition cost recovery. SDG&E asserts, however, that if the unbundling proceeding results in the elimination of the hazardous waste balancing account for generation operations, SDG&E should then be able to seek transition cost recovery for these costs in the annual transition cost proceedings.

In general, ORA would not take issue with the transition cost recovery of the environmental compliance regulatory asset, so long as provisions for a true-up are included in the accounting mechanisms. However, ORA concurs with the auditors that PG&E's estimating and allocation methodologies are not clear, and thus these costs should not be eligible for transition cost recovery until the independent auditors are satisfied with the reasonableness of this methodology. ORA recommends that if these costs are afforded transition cost recovery, PG&E's estimates should be made subject to refund until ORA has reviewed this account in PG&E's upcoming GRC.

TURN and FEA propose to exclude these costs from transition cost recovery. TURN recommends excluding PG&E's estimates of environmental compliance costs because they are not linked to any specific environmental projects at generating plants. Moreover, PG&E did not determine with any specificity which, if any, sites were generation-related. PG&E states that costs at specific generating plants are excluded from the HSM and the ECM; however, TURN explains that PG&E allocated costs to generation based on an allocation factor that includes all generation sites. TURN concludes that such costs are based on speculative estimates and also believes that there is great potential for double-counting with decommissioning costs or capital additions. TURN prefers Edison's methodology for estimating these costs, but insists that the timing of the spending is not definite, nor is it clear whether or not these costs may be reflected in plant divestiture. TURN recommends that if any of these costs are eligible for transition cost recovery, the funds collected should be treated as rate base offsets until the money is actually spent on generation-related projects.

FEA agrees with the auditors that PG&E was unable to substantiate its methodology for determining that the clean-up costs equal 28% of its plant assets and how these were allocated to the generation function. FEA is concerned about PG&E's proposal to collect generation environmental compliance costs from electric and gas transmission and distribution customers. FEA contends that these costs should be recovered in prices charged for electric generation; collection of these costs through transmission and distribution rates would confer a competitive advantage on the utilities. FEA recommends that because Edison has not been authorized to recover these costs as a regulatory asset and Edison has not substantiated the reasonableness of these estimated costs, this amount should be excluded from transition cost recovery.

We agree with the auditors that the nature of the costs recorded in the ECM account is speculative. PG&E's methodology underscores the uncertain nature of determining these costs. In D.97-06-060, we stated, "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 is established."

(D.97-06-060, mimeo. at p. 44.) We decline to grant transition cost recovery for this regulatory asset over the 48-month transition period because of the uncertain and indefinite nature of these costs. We see no reason to increase transition costs because of "phantom" costs that may or may not occur in the future. Indeed, the development of the cost estimates does not appear to fit the criteria established by SFAS 71. We find that recovery of these uncertain future costs is not allowed under § 367: these may be generation-related regulatory assets, but the costs were not being collected in rates as of December 20, 1995. We will not allow any costs to be charged to the transition cost balancing account at this time. If environmental compliance costs are actually incurred and spent on generation-related projects, the utilities may request recovery in the annual transition cost proceedings. It is not reasonable to allow these sorts of speculative costs to add to the already large transition cost bill. This approach is consistent with our findings in D.97-08-056, in which we determined that as of January 1, 1998, allowing entries into PG&E's and Edison's Hazardous Substance Clean-up and Litigation Cost Accounts (also called HSM accounts) for additional generation-related costs would confer a competitive advantage on these utilities.

17.6. Gain or Loss on Reacquired Debt and Preferred Stock

As Edison explains, this issue encompasses not only the costs of reacquiring debt and preferred stock, but also the debt and preferred stock premium or discount associated with each issuance. Edison's regulatory assets and obligations include costs and discounts associated with debt issuances plus costs associated with reacquiring and reissuing preferred stock. Under current ratemaking, these costs are recovered through the embedded cost of debt. Future costs may arise as a result of the utilities' reducing debt and preferred stock levels in their capital structures.

PG&E has reported future cost estimates for the amortization of the recorded loss on reacquired debt account, which is categorized as a regulatory asset, and does not ask for recovery of the unamortized debt discount. PG&E is seeking recovery for both past unamortized losses on debt costs and for any future losses that may be incurred. The amortized loss balance, net of any gains, was updated for

December 31, 1997, to reflect changes in the 1995 balance, taking into account normal amortization of the loss. The loss on reacquired debt is amortized over the remaining life of the original debt reacquired and retired. The auditors tested the December 31, 1995 balance and believe that this amortization is reasonable. The auditors, however, question as speculative and unreasonable the additional costs related to the forecasted losses in 1997. The auditors state that PG&E's assumptions associated with the 1997 recallable bonds may or may not materialize depending on the economic benefit at the time of recall in 1997. The auditors recommends that we establish criteria for allowing the utilities to retire debt and to recover any associated losses in the transition cost balancing account. If the 1997 callable debt does meet this established criteria, the auditors recommend that the calculation of any loss be determined at the time the debt is retired.

PG&E contends that the retirement of debt in 1997, including any loss on reacquired debt, is consistent with anticipated reacquisitions or refinancings of debt. PG&E maintains that true-ups will be made when actual information is available. PG&E states that the actual recorded value of the regulatory asset as of December 31, 1997 will be the basis for transition cost recovery.

Edison recommends that all recorded unamortized debt costs that are currently being recovered through the embedded cost of debt element in the rate of return continue to be recovered in this fashion. Edison explains that this is necessary because it is not possible to separate debt and preferred stock costs related to the part of the capital investment that is being reduced. Thus, the unamortized costs will decline as restructuring continues and issues mature without being replaced. As capital investment associated with generation is reduced, the remaining unamortized debt and preferred stock expenses will be supported by transmission and distribution plant. Edison and TURN agree that these costs are not stranded. Edison recommends that any future costs incurred to reacquire debt and preferred stock, which would be identifiable as transition-related, should be collected through the transition cost balancing account, rather than through the embedded cost of debt.

SDG&E proposes to recover both losses on reacquired debt and unamortized debt discount by way of transition cost recovery. The auditors do not question the amortization of either the December 31, 1995 balances for SDG&E or the additional amounts as of January 1, 1998.

FEA asserts that only actual incurred losses should be allowed for transition cost recovery. TURN, as noted above, agrees with Edison that costs associated with past transactions should not be eligible for transition cost recovery because they are not stranded. Unamortized costs will follow the existing debt issues to non-generation uses. TURN concurs with Edison's expectation that most of the bonds would not be called but would shift from generation to distribution.

TURN recommends that the allowance of future costs related to losses on reacquired debt as a result of calling debt because of the issuance of rate reduction bonds or other transition cost recovery must be read very narrowly. TURN urges that costs and benefits must be aligned and believes that it would not be equitable to collect CTC from ratepayers for the costs of calling in more expensive debt, only to allow the utilities to keep the savings resulting from the reduced embedded cost of debt. TURN maintains that a distribution utility has much less risk than a generating utility and could operate with a more leveraged capital structure, and that furthermore we must evaluate prudence issues with regard to debt issuances made in the 1995-97 time period when restructuring efforts were pending. TURN recommends that if either of the requested debt cost components are deemed eligible for recovery, we must adjust ratemaking to prevent double-counting, because the embedded cost of debt already contains a component to pay for losses on reacquired debt and unamortized debt discounts.

We agree with Edison and TURN that past unamortized debt costs included in the embedded cost of debt and should not be accounted for in the transition cost balancing account. Such an accounting would be complicated and has the potential to lead to double-counting. However, we are not similarly convinced regarding future losses. Section 840(f) reads:

"'Transition costs' means the costs, and categories of costs, of an electrical corporation for generation-related assets and obligations, consisting of generation facilities, generation-related regulatory assets, nuclear settlements, and power purchase contracts, including, but not limited to, voluntary restructuring, renegotiations, or terminations thereof approved by the commission, that were being collected in commission-approved rates on December 20, 1995, and that may become uneconomic as a result of a competitive generation market in that those costs may not be recoverable in market prices in a competitive market, and appropriate costs incurred after December 20, 1995, for capital additions to facilities existing as of December 20, 1995, that the commission determines are reasonable and should be recovered, provided that these costs are necessary to maintain the facilities through December 31, 2001. Transition costs shall also include the costs of refinancing or retiring of debt or equity capital of the electrical corporation, and associated federal and state tax liabilities."

On August 15, 1997, SB 477 was signed into law by Governor Wilson. Among other things, SB 477 amends § 367 by adding the following sentence:

"These uneconomic costs shall include transition costs as defined in subdivision (f) of Section 840, and shall be recovered from all customers or in the case of fixed transition amounts, from the customers specified in subdivision (a) of Section 841, on a nonbypassable basis...."

While SB 477 also amends § 840, it does not modify the language of § 840(f).

Pursuant to the law, we will allow the recovery of future costs associated with future losses incurred to reacquire debt and preferred stock as of January 1, 1998. While we are swayed by Edison's argument that the utilities have incentives to maintain an optimal capital structure, we will allow only those costs actually incurred, net of any gains, and carefully review such costs in the annual transition cost proceedings. We will require the utilities to make a showing at that time to demonstrate that adequate ratemaking safeguards are in place to ensure that the savings in the embedded cost of debt are adequately accounted for and that no double-counting has occurred.

17.7. Deferred Taxes

During informal workshops announced at evidentiary hearings and open to all parties, PG&E, Edison, SDG&E, ORA, and TURN were able to achieve consensus on property-related tax issues, PG&E's vacation pay deferred tax asset, and Edison's ad valorem lien date tax asset and presented a joint proposal addressing these issues (Exhibit 101). The parties sponsoring Exhibit 101 were available for cross-examination as a panel. These parties agree that transition cost taxes (also known as regulatory tax receivables) are fully eligible for recovery during the transition period. Parties have also agreed that all property-related regulatory tax receivables or payables will be amortized to zero by the end of the transition period, which will settle all property-related tax benefits or obligations between ratepayers and utilities, except as provided for in the decisions related to Diablo Canyon (D.97-05-088), Palo Verde (D.96-12-083), and SONGS (D.96-01-011 and D.96-04-059). Thus, the parties to this stipulation believe that the goals of the Preferred Policy Decision and AB 1890 are met and that this treatment fairly shares the benefits and costs during the transition period, concludes the obligations between ratepayers and utilities at the end of the transition period, and accommodates the requirements imposed by taxing authorities.

Although choosing not to participate in the tax workshops, EPUC now asserts that no tax regulatory assets are eligible for approval, because of the specific language of § 367(c).

We do not agree with EPUC. This joint proposal fairly addresses the property-related tax issues raised by parties to this proceeding, with regard to deferred tax liabilities, deferred tax assets, and deferred tax reserves. We adopt this stipulation, included in this decision as Attachment 5, and commend the parties for working through these complex issues. We particularly appreciate the clear, concise definitions and explanation of the ratemaking tax algorithm included in Appendix D to Exhibit 101.

17.8. Balancing Accounts

In compliance with the requirements of AB 1890 and D.96-12-077, PG&E, Edison, and SDG&E established Interim Transition Cost Balancing Accounts (ITCBA), effective January 1, 1997. PG&E recommends transforming any balance in the CAC account and the ERAM account as of December 31, 1997 to the ITCBA first, then to the Transition Cost Balancing Account (TCBA). PG&E proposes to eliminate ECAC and ERAM during the transition period and recover the cost categories addressed in these accounts through its proposed Transition Revenue Account (raised in the workshops addressing streamlining in the electric restructuring rulemaking, R.94-04-031/ I.94-04-032). For all costs incurred after December 31, 1997, PG&E agrees with CIU that costs which are not eligible for transition cost recovery and which are currently recovered in the ECAC or ERAM (for example, going forward costs for non-must-run fossil plants) should not be recovered in the transition cost balancing account. PG&E states that it does not propose to debit such ineligible costs to its transition cost balancing account. However, PG&E disputes FEA's proposal to remove such ineligible costs before December 31, 1997, because these costs were incurred under the current regulatory framework and, for ECAC costs, are subject to reasonableness review. If we find that these costs are not reasonable, PG&E states its intent to remove those costs at that time. The December 31, 1997 ERAM balance is not subject to reasonableness review, but is based on authorized GRC base revenue amounts with changes to reflect sales fluctuations.

Edison explains that the ITCBA was established to hold any overcollections in the ECAC and ERAM balancing accounts as of December 31, 1996, (see § 368 (a)) to receive the balances in the ECAC and ERAM balancing accounts on December 31, 1997, and to accrue any interim transition costs that the Commission may approve for recovery. Edison will transfer the balances in the ITCBA when the final transition cost balancing accounts are approved. Edison proposes to transfer the December 31, 1997 balances in the ITCBA, the SONGS 2&3 ICIP balancing account, and the Palo Verde Incremental Costs balancing account to the TCBA as subaccounts. Edison disputes CIU's and FEA's contention that we must take care to remove any costs not eligible for transition cost recovery from the ECAC and ERAM balancing accounts before those accounts are transferred to the TCBA. Edison explains that any balance remaining in the ECAC or ERAM balancing accounts as of December 31, 1997 will have arisen from differences between authorized and recorded costs and revenues since the date of the last true-up of those accounts, and therefore, cannot be considered going forward costs. Aside from our policy that overcollections resulting from disallowances should be directly refunded to ratepayers rather than credited against transition costs, Edison asserts that there is no restriction to crediting overcollections or debiting undercollections in the ECAC and ERAM balancing accounts as of December 31, 1997 against transition costs.

SDG&E states its intent to record any overcollections in the ECAC and ERAM balancing accounts as of December 31, 1997 to the TCBA, which it believes is consistent with the mandates of AB 1890 and the requirements of D.96-12-077. ORA recommends that it is the recorded balancing account balances as of January 1, 1998 which should be the basis for transition cost recovery.

We concur that it is equitable to allow transition cost recovery for both undercollections and overcollections accrued in the ECAC balancing accounts as of December 31, 1997. This finding was addressed in D.96-12-077:

> For 1997, authorized ECAC revenues will continue to be a part of the authorized revenue requirement. The balancing function of ECAC will operate somewhat differently as a result of the rate freeze. If ECAC costs are higher than forecasted, then authorized revenues will be insufficient to cover these costs, and the resulting "undercollection" will eventually result in a higher authorized revenue requirement (assuming the costs are reasonable and subject to the rate freeze). Since rates may not rise to amortize the undercollection, however, the effect is to reduce the headroom revenues available for crediting to the interim TCBA. Similarly, if ECAC costs are lower than forecasted, a larger headroom and greater credit to the interim TCBA will result.

Balances in PG&E's, Edison's, and SDG&E's ECAC and ERAM accounts should be transferred to the ITCBAs or the TCBAs, if established, as of December 31, 1997, as part of the "closing" of those accounts. The ITCBA, in turn, should be closed out to the TCBA established for each utility. We emphasize that reasonableness reviews will continue for these amounts. To the extent headroom is insufficient to address any ECAC or ERAM undercollections, these amounts may not be carried over to later years for transition cost recovery, nor are such costs to be accumulated for later collection. The rate freeze is just that - a freeze, rather than a deferral.[24]

The auditors have confirmed the amounts included as credits in the ITCBA to account for the 1996 ECAC and ERAM overcollections for each utility:

PG&E: $ 51.6 million

Edison: $220.4 million

SDG&E: $ 98.1 million

We intend to carefully oversee and review the transfer of balances into the TCBA, including verifying the balances in the ECAC and ERAM balancing accounts. In addition, we will ensure that all headroom revenues, which may have been recovered in various utility accounts under the rate freeze, are properly credited to the TCBA. We direct the Energy Division to oversee an audit of the balances transferred to the TCBA and the headroom revenues. The Energy Division may select independent auditors to undertake this audit, if necessary. The audit report should be issued by December 31, 1998. If independent consultants are hired, we will require the utilities to pay for the audit, in proportion to the audit expense incurred. The utilities should file an advice letter on December 12, 1997 which details the costs and revenues to be transferred to the TCBA.

17.9. PG&E's WAPA Regulatory Asset

PG&E has a long-standing contract, terminating January 1, 2005, with the Department of the Interior, Bureau of Reclamation, Western Area Power

[24] As provided for in the proposed streamlining decision, ERAM accounts should be eliminated as of January 1, 1998. Edison no longer has an ERAM account. SDG&E's ERAM account no longer serves its original, intended purpose. PG&E's Transition Revenue Account will substitute for ERAM, to a certain extent.

Administration (WAPA) which is an exchange of power that includes requirements to coordinate the PG&E and WAPA electrical systems. When WAPA has excess power, the power is supplied to PG&E. PG&E then incurs an obligation to send power to WAPA at an unspecified future time. Power received from WAPA generally costs less than power supplied by PG&E. To account for these transactions, PG&E records a regulatory liability from WAPA with a corresponding regulatory asset which represents a receivable from ratepayers, which is then recoverable in a subsequent ECAC proceeding.

The auditors had not received enough information from the company to verify the WAPA regulatory asset balance. PG&E requested and was allowed to update its data by presenting additional information to the auditors. While the auditors continue to believe that the WAPA regulatory asset is eligible for transition cost recovery, they also recommend that this balance remain in the category of a questioned cost because PG&E has not presented detailed estimates in a manner which they can review adequately. The auditors explain that PG&E anticipated a FERC filing in July or August 1997 which would true-up the transactions through December 1995. This filing can be relied upon to substantiate the WAPA liability and regulatory asset balance as of December 31, 1995.[11]

The auditors recommend that PG&E prepare a reconciliation of the settlement amounts and provide documentation showing that accounts have been properly adjusted; this settlement amount should then become the basis for the eligible transition cost balance as of December 31, 1995. The auditors also recommend that PG&E show the necessary calculations to enable parties to discern how monthly dollar values are developed and added together to produce estimated account activity for the

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[11]On September 18, 1997, PG&E served on all parties to this proceeding the August 30 filing submitted to FERC which proposes true-up rates for the WAPA-PG&E exchange agreement. This filing proposes true-up rates for 1994 and 1995 energy and capacity rates and based on these proposed revisions, WAPA owes PG&E approximately $6.2 million.

two years ended December 31, 1997, but believe that additional testing of PG&E's work in regard to these data elements is not necessary.

PG&E agrees with this recommendation and proposes that the Commission review these calculations in the first annual transition cost proceeding. PG&E proposes to amortize the WAPA regulatory asset based upon actual recorded levels beginning January 1, 1998, with any differences from estimates subject to review in the annual transition cost proceedings. ORA supports the recovery of the WAPA regulatory asset. FEA recommends excluding this regulatory asset from transition cost recovery until PG&E provides the necessary support and required calculations.

We will adopt the auditors' recommendations and will require PG&E to support the calculations for the December 31, 1997 WAPA regulatory asset balance in the first annual transition cost proceeding by providing a detailed explanation of the monthly dollar amounts and how these amounts result in the regulatory asset balance. We will allow PG&E to amortize the WAPA regulatory asset or liability based on the substantiated December 31, 1995 balances.

17.10. PG&E's QF Buyout Regulatory Asset

PG&E has identified five QF contracts that were restructured or bought out prior to December 31, 1995. In accordance with generally accepted accounting principles, PG&E recorded the present value of this buyout liability and recorded a corresponding regulatory assets, anticipating Commission approval of recovery of these costs. Following the audit report, PG&E disclosed that it had discovered certain errors in the net present value calculations and revised them accordingly. The auditors performed additional analysis to verify these amounts. The auditors have confirmed that the adjusted balances for the QF Buyout regulatory asset are $173.2 million and $40.6 million as of December 31, 1995 and January 1, 1998, respectively. The auditors explain that these are still questioned costs because the Commission has not yet issued its decision in the ECAC proceeding in which PG&E seeks approval of the agreements and recovery of the related costs. PG&E states that it will adjust the balance of this regulatory asset to reflect any adjustment made by the Commission.

FEA accepts the restated amounts, but recommends that this regulatory asset would represent a cost eligible for transition cost recovery only when it is approved by the Commission.

Similar to our treatment of Edison's fuel and fuel transportation contracts which are not yet approved, we provide that the QF Buyout Regulatory Asset amounts for costs incurred prior to December 31, 1995 should be tracked in a memorandum account and transferred to the transition cost balancing account upon our determination of reasonableness.

18. Rate of Return Issues

In this proceeding, we must determine two important issues related to rate of return. First, we must decide when and to which assets the reduced return applies to non-nuclear transition cost assets; for example, plant assets are traditionally subject to the return on rate base, while other assets, such as fuel inventories, balancing account over- and undercollections, or regulatory assets, either earn the commercial paper interest rate or no rate of return.[25] Second, we must determine the appropriate embedded cost of debt rate to use in calculating the lower return.

In the Preferred Policy Decision, we found that a reduced return on equity was appropriate for those utility assets afforded transition cost recovery to reflect the reduced business risk associated with the recovery of the remaining net investment due to the imposition of a nonbypassable charge on distribution customers. (Preferred Policy Decision, mimeo, p. 124.) We have affirmed that the reduced return on equity set forth in the Preferred Policy Decision needs no adjustment at this time and that AB 1890 confirms this treatment:

> "Further, we agree that AB 1890 confirms the rate of return on equity we adopted in the Preferred Policy Decision. PU [Public Utilities] Code Section 367(d) states, in pertinent part: 'Recovery of costs prior to

[25] The applicable reduced rates of return have been considered previously for nuclear generation assets in D.96-04-059, D.96-12-083, and D.97-05-088.

December 31, 2001, shall include a return as provided for in Decision 95-12-063, as modified by Decision 96-01-009, together with associated taxes." (D.97-07-059, mimeo. at p. 2 quoting D.96-12-088, mimeo. at 33.)

On February 24, 1997, ORA filed a motion in R.94-04-031/I.94-04-032 requesting an immediate ruling ordering PG&E, Edison, and SDG&E to implement the provisions regarding the reduced return on equity. Timely responses to ORA's motion were filed by PG&E, Edison, SDG&E, and TURN.

We responded to this motion in D.97-07-059 by directing PG&E, Edison, and SDG&E to establish memorandum accounts to track the difference in revenue requirements between the authorized revenue requirement and the maximum reduction in revenue requirements. We also stated that we would not decide the merits of ORA's proposal without a full consideration of the interaction of the rate of return and transition cost recovery. Because this motion was filed and served in the electric restructuring rulemaking, but rate of return issues associated with transition cost recovery are being addressed in the transition cost proceedings, we allowed supplemental testimony or briefs to be submitted in Phase 2 of this proceeding. By ruling of July 25, 1997, the ALJ established that supplemental opening briefs would be filed on August 8 and supplemental reply briefs would be filed on August 18. We will summarize the positions of parties on these issues, either as articulated in the briefs.

ORA and TURN submit that the reduction in the return on equity should be implemented now because the utilities' risk of recovering their investments has already been reduced. ORA and TURN believe that several aspects of the statute have combined to substantially reduce the risk of recovery of eligible transition costs, including the establishment of the nonbypassable CTC, the implementation of the rate freeze, and the imminent issuance of the rate reduction bonds. ORA and TURN contend that beginning the rate freeze on January 1, 1997 creates headroom which in turn allows the utilities to begin collecting revenues to apply to transition costs prior to the beginning of the transition period. ORA argues that this increased headroom would increase the likelihood that utilities would be able to recover their transition costs within the specified time period and could result in early recovery of those costs, so that the rate freeze could end early.

ORA believes that this reduction in authorized revenue requirements would have been most appropriately applied beginning on January 1, 1997, when the rate freeze began, pursuant to D.96-12-077. In that decision, we also established interim balancing accounts to ensure that excess revenues collected under the rate freeze would be allocated to reducing transition costs. (D.96-12-077, mimeo. at pp. 12-13.) ORA recommends that a corresponding ratepayer benefit should be adopted. TURN supports ORA's proposal and emphasizes that the reduction in the return on equity portion of assets eligible for transition cost recovery will increase the likelihood of the utilities achieving full recovery of their stranded investment during the transition period. TURN also believes that this proposal will make recovery of transition costs more orderly, as required by § 330(t), because the reduced rate of return would be implemented at approximately the same time as the risk-reducing measures go into effect.

Furthermore, ORA and TURN argue that the reduced return should be applied to all utility generation rate base, not merely to those assets which are recovered on an accelerated basis. ORA and TURN explain that it is the opportunity to accelerate recovery of these asses, not the actual acceleration, which reduces the risk of recovery and thereby justifies the reduced rate of return. ORA and TURN are concerned that applying the reduced rate of return only to accelerated assets, rather than to all assets eligible for acceleration, would encourage gaming of this process. ORA and TURN contend that the utilities could have the incentive to forestall acceleration of as many assets as possible consistent with achieving full recovery during the rate freeze period, in order to maximize the return earned on those assets; therefore, the rate of return on various plant assets would vary not because of any difference in risk of recovery, but merely because of the acceleration decision. ORA and TURN recommend applying that reduced rate of return immediately to all assets eligible for transition cost recovery.

ORA and TURN also argue that D.97-07-059 is in error in prescribing use of 1995 cost of debt figures to compute the reduced return on equity for PG&E, Edison, and

SDG&E. ORA and TURN assert that D.96-04-059, which stated the fixed 1995 cost of debt should be broadly applicable, can apply only to SONGS assets only. ORA contends that these issues were not properly before the Commission in the SONGS settlement addressed in the Edison Test Year 1995 GRC (in which proceeding D.96-04-059 was issued), nor should the broad applicability have been addressed in D.97-07-059. ORA explains that the embedded cost of debt is traditionally determined in the annual cost of capital proceedings and the most recent determination of this component should be used to compute the reduced rate of return. ORA recommends that to the extent parties have negotiated a specific cost of debt as part of a settlement which has been approved by the Commission, it is that embedded cost of debt which should be the basis for the reduced return on those particular assets. For all other assets eligible for transition cost recovery, ORA recommends using the embedded cost of debt adopted in D.96-11-060 (the most recent cost of capital decision) to compute the reduced return on equity for each utility.

PG&E, Edison, and SDG&E recommend that we reject ORA's motion, because transition cost recovery will not begin until January 1, 1998; i.e., the non-nuclear generation assets will not receive accelerated depreciation treatment until that date. SDG&E states that D.96-11-060, the 1997 cost of capital decision, adopts an all-party settlement, to which ORA was a signatory. SDG&E believes that by seeking a reduction to the return on equity on assets which are eligible for transition cost recovery, ORA undermines its position in the cost of capital proceeding, and essentially seeks a rehearing of D.96-11-060, which is out of time.

PG&E also agrees that accelerated recovery of the uneconomic generation assets must be authorized before the reduced return component applies and that ORA's proposal is premature because the essential elements of the transition cost recovery framework are not yet fully implemented. PG&E states that a reduced return is appropriate only when an asset is determined to be uneconomic and the utility seeks to accelerate the recovery of that asset. Furthermore, PG&E states that the reduced return can apply only to fossil-fueled generation, pursuant to the Preferred Policy Decision, which PG&E believes clearly distinguishes between the treatment of fossil and hydroelectric assets. PG&E also claims that § 368(a) requires a distinction between returns applicable to economic and uneconomic assets, because it requires that "each utility shall amortize 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."

While PG&E acknowledges that the rate freeze has begun and makes revenues available to offset transition costs, it does not make any excess revenues available to those assets which are not accelerated. PG&E claims that neither the establishment of the ITCBA, the implementation of interim transition charges, nor the statutory authorization of the CTC reduces the utilities' risk of recovery of these assets; only the accelerated amortization of assets reduces the risk of recovery. Moreover, PG&E contends that it is not appropriate to reduce the rate of return applicable to economic assets, since these assets will not be accelerated or recovered in the transition cost balancing account. PG&E had used its 1996 cost of debt in calculating the reduced return on equity in its prepared testimony in this proceeding, but states that it would not be opposed to using the 1995 cost of debt.

Edison agrees that the reduced rate of return is tied to the accelerated recovery of generation assets and argues that neither the rate freeze, the nonbypassable CTC, nor implementation of the interim CTC justifies applying a reduced return to generation assets.[36] Edison concurs with PG&E that because in the Preferred Policy Decision, we established that the utilities would retain ownership of their hydroelectric assets, which would remain subject to traditional regulation, the reduced rate of return should not be applied to these assets. Edison recommends that the reduced rate of return should apply to Edison's fossil generation, once that generation has been market-valued and suggests that strict application of the principles articulated in the Preferred Policy

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[36] Edison filed a motion on August 11 to request that we accept its supplemental opening brief one day late, due to problems with its messenger service and the UPS strike. We grant that motion and Edison's supplemental opening brief is accepted for filing as of August 11, 1997.

Decision would mean that any generation assets not divested would not be subject to accelerated recovery until market valuation takes place. Edison explains that this approach is consistent with its position in Phase 1, in which it proposed to apply the reduced rate of return to assets that are being recovered on an accelerated basis, but a full rate of return would apply until that accelerated recovery begins.

SDG&E contends that ORA's motion to apply the reduced rate of return as of January 1, 1997 or February 7, 1997 (the date the motion was filed) should be dismissed, because retroactively implementing the reduced rate of return would constitute retroactive ratemaking. SDG&E also thinks the reduced rate of return is inextricably linked to the accelerated depreciation of the non-nuclear generation-related assets, and ORA's request directly contradicts D.96-11-060, the most recent cost of capital decision, and D.96-12-088, the Roadmap 2 decision. SDG&E disputes ORA and TURN's allegation regarding gaming, because SDG&E believes that the guidelines established in D.97-06-060 will preclude such gaming.

18.1. Discussion

In the Preferred Policy Decision, we found that it was appropriate to reduce the cost of capital for generation assets eligible for transition cost recovery by setting the return on the percentage of the undepreciated asset financed by equity at 10% below the long-term cost of debt. We also found that this reduced return was the appropriate measure of the reduced risk associated with these assets as the utilities recovered the net book value of such assets through accelerated depreciation. At the same time, we recognized that this 10% reduction could be eliminated by the utility divesting at least 50% of its fossil generation and stated that we would provide for a 10-basis point increase in return on equity for each 10% of fossil plants divested.

Furthermore, we found that ratepayers should benefit to some degree from our treatment of transition costs and that it would be inappropriate to require ratepayers during the transition to bear the same costs they would have borne in the absence of moving toward a competitive framework. We also found that it was equitable that shareholders recover somewhat lower revenues for transition cost assets than they would under traditional cost-of-service regulation and that assurance of full recovery would have the potential of providing perverse incentives to utility market behavior. The assurance of full recovery would allow the utility to remain indifferent to the level of transition costs and could even result in incentives to bid low in offering output to the Power Exchange, which could then depress the market-clearing price and further increase transition costs. Finally, we found that adopting a reduced return on equity was appropriate in light of the reduced risk of recovery and would not adversely impact the utilities' financial stability.

As stated in D.96-12-088, AB 1890 confirms the return on equity adopted in the Preferred Policy Decision. Although accelerated amortization of certain transition cost assets has not yet begun, the rate freeze commenced on January 1, 1997, pursuant to D.96-12-077. The utilities may be using this interim period to accrue revenues to offset transition costs.

We do not agree with the utilities that the application of the reduced rate of return is inextricably linked to the accelerated amortization of generation assets. In the Preferred Policy Decision, we established that we are not required to guarantee full transition cost recovery, and this has been affirmed in AB 1890. We also clarified that in allowing the utilities the opportunity to recover generation plant-based transition costs, we were also establishing an appropriate risk-based rate of return. We explained some of the genesis of our decision-making process and provided background information on Humboldt Bay Unit III and SONGS I, for which we provided shareholders less than full recovery of the combination of sunk costs and rate of return at the weighted cost of capital. (45 CPUC2d 274; 11 CPUC2d 532.) Neither of these decisions linked these outcomes with accelerated depreciation, although accelerated depreciation was allowed for SONGS I at the authorized rate of return. Furthermore, in D.85-08-046, we specifically established that while PG&E should recover the remaining net plant investment of Humboldt Bay 3 over a four-year period, no return was allowed on the unamortized balance:

> "With respect to PG&E's equity argument, we observe that plants which have exceeded their estimated useful lives have been fully

> depreciated. Thus, the shareholder has already recovered his entire investment and a fair return on that investment from the ratepayer. The ratepayer who has paid for the entire plant is entitled to receive any additional benefit from the plant's continued operation. In the case of premature retirement, the ratepayer typically still pays for all of the plant's direct cost even though the plant did not operate as long as was expected. The shareholder recovers his investment but should not receive any return on the undepreciated plant. This is a fair division of risks and benefits." (D.85-08-046, 18 CPUC2d 592, 599.)

In allowing the recovery of generation plant-related transition costs, we have, in effect, allowed the utilities to recover costs of plants that may no longer be used and useful in the new competitive marketplace. In the Preferred Policy Decision, we stated:

> "We expect that some utility plants will no longer be used and useful in the future restructured energy marketplace. Allowing recovery of remaining net investment associated with the SONGS I plant at the embedded cost of debt was reasonable at the time, given the then-current regulatory structure. However, today's decision decreases the risk associated with recovery of remaining net investment (now part of transition costs), due to the imposition of a nonbypassable charge on distribution customers...which decreases utility business risk." (Preferred Policy Decision, mimeo. at 124.)

We agree with ORA and TURN that this decreased business risk trigger the reduced rate of return. We tie the application of the reduced rate of return, not to accelerated depreciation, bur rather to the reduced risk because transition cost recovery was allowed in the first place. The necessary components of this decreased risk are in place, contrary to PG&E's and Edison's contentions. Indeed, these elements were firmly established when AB 1890 was signed into law and established that the utilities would have a reasonable opportunity to collect uneconomic costs and affirmed the nonbypassable competition transition charge. In addition, by starting the rate freeze on January 1, 1997, we have allowed the utilities the opportunity to accrue revenues that will serve to offset transition costs. The ratepayers might otherwise have enjoyed the benefits of lower rates. It is therefore equitable that the reduced rate of return apply to those generation plant assets that are currently in rate base and that are eligible for transition cost recovery. Furthermore, this reduced rate of return should have been applied as of January 1, 1997; we agree with SDG&E, however, that we cannot apply this reduced rate of return before the date on which the utilities established the memorandum accounts ordered in D.97-07-059.

Furthermore, we are persuaded that, for non-nuclear generation plant, the relevant cost of debt to be used in the calculation of the reduced return on equity is that adopted in D.96-11-060, in the 1997 cost of capital proceeding. While D.96-04-059 addressed the broad applicability of the concept of a fixed cost of debt, proper notice was not provided to all parties to the electric restructuring rulemaking that this decision, issued in Edison's 1995 Test Year GRC, had applicability beyond the SONGS 2&3 settlement. Fixing the reduced return on equity at 90% of the 1995 cost of debt for all utilities could impact parties' rights. We have carefully considered the reduced return on equity adopted in D.96-04-059 and D.97-07-059. Based upon the briefs and comments in this proceeding, the record developed in this proceeding now persuades us to reconsider fixing the reduced return on equity at 90% of the 1995 embedded cost of debt. It is more reasonable to establish the reduced return on equity at 90% of the 1997 embedded cost of debt adopted in D.96-11-060, which reflects the most recent information regarding risk and reward as reflected in the cost of capital. D.97-05-088 adopted a reduced rate of return for Diablo Canyon based on the 1996 cost of capital decision (D.97-05-088, mimeo., Finding of Fact 41 at p. 79; PG&E Opening Brief, p. 136.) We agree with the concept that the measure of the embedded cost of debt should remain fixed for the entire term of the transition period or the relevant amortization period, irrespective of changes in the actual utility embedded cost of debt. However, as a benchmark, PG&E, Edison, and SDG&E shall use the embedded cost of debt adopted in D.96-11-060 to calculate the reduced return on equity for transition cost recovery of generation-related plant assets. The reduced rate of return is 7.13% for PG&E, 7.22% for Edison, and 6.75% for SDG&E. For the nuclear generating plants, the reduced rate of return should be that established in D.96-04-059, D.96-12-083, and D.97-05-088 for SONGS 2&3, Palo Verde, and Diablo Canyon, respectively.

19. Issues for Transition Cost Annual Reviews

PG&E recommends that the filing date of June 1, 1998, as established for the first annual transition cost proceeding in D.97-06-060, is not consistent with recovery of 1999 transition costs on an ex post basis. Instead, PG&E recommends changing this date to require a filing by early 1999 (no later than May 1) for review of transition costs recorded in 1998. PG&E intends to provide a report of all entries to the transition cost balancing account, as well as the balances and returns used to develop transition cost revenue requirements, the assumptions used in estimating market value, the results of any actual market valuations, any changes in revenue requirements resulting from capital additions proceedings, changes in amortization schedules due to changes in market value estimates or actual market valuations, and any additional acceleration beyond the 48-month amortization schedule. PG&E also recommends a review of the entries to the must-run and non-must-run fossil memorandum accounts.

PG&E recommends that the annual proceeding should be an ex post review to determine that the transition cost balancing account entries are correct, based on recorded amounts, subject to any constraints adopted in this proceeding, the capital additions proceedings or generation PBR proceedings. PG&E strongly cautions against a prudence review of costs, other than QF buyout costs, although PG&E recognizes that certain costs must be reviewed for reasonableness by the Commission, including employee-related transition costs, WAPA true-ups, and must-run operating costs if not recovered though the ISO (because this is consistent with PG&E's placeholder proposal in this regard). PG&E agrees with ORA that there should continue to be reasonableness review of QF, purchased power, and geothermal steam contract administration costs, as well as of its water purchases. PG&E disagrees with ORA's recommendation to review Helms pumped storage costs, because PG&E believes that since power purchased for pumping purposes would be at the market-clearing price, reasonableness reviews are unnecessary.

PG&E recommends that these proceedings also audit the costs associated with operations and revenues received from the ISO and the Power Exchange. However, because scheduling of must-take resources, QF generation, and PG&E's own generation resources will be under FERC jurisdiction, PG&E recommends that no review of PG&E's bidding strategy occur in the annual transition cost proceedings. Thus, PG&E believes that the creation of the Power Exchange and the ISO transfers to FERC the oversight for ensuring that PG&E matches load and resources to provide least-cost, reliable service.

Edison proposes to file monthly and annual reports which address the recorded transition cost balancing account entries, similar to the monthly ECAC balancing account reports currently submitted to the Commission. Edison agrees with the timing of the first annual transition cost proceeding and recommends that this proceeding address forecast issues, estimated transition cost recovery in the following year, forecast capital additions, and estimated market value of assets subject to market valuation. Edison also recommends that this proceeding address reasonableness issues, including accelerated recovery of transition costs, review of recorded transition cost balancing account entries (including any recorded capital additions), contract administration, and the results of any plant valuations.

Edison recommends that since the annual transition cost application will be filed on June 1 of each year, the recorded information provided for review should cover the record period of April through March, similar to its current ECAC record period. For example, the June 1998 application would contain transition cost balancing account entries for January - March 1998. The June 1999 application would contain entries for April 1998 through March 1999.

ORA supports PG&E's suggestion to report recorded costs to date and focus in the first proceeding on reviewing future amortization schedules. ORA recommends that the utilities' management of power purchase contracts and QF contracts, PG&E's geothermal steam contracts, and PG&E's and Edison's water purchases and pumped storage operation costs all be addressed for reasonableness in the annual proceedings, which should also be used to address the determination of the uneconomic portion of Edison's coal contracts.

SDG&E succinctly recommends that the Commission address two groups of costs in the annual proceedings: an accounting of the previous year's expenditures and revenues and a review of any new costs which should be recovered as transition costs; e.g., employee-related transition costs. The amount of currently authorized generation-related operating expenses included in base rates should be confirmed as an upper limit as to how much can be recovered for going forward operating costs when an individual unit is required for reactive power/voltage support.

FEA recommends requiring the utilities to mitigate their transition costs and that these mitigation efforts should be the subject of annual Commission review.

19.1. Discussion

We have previously determined that all transition cost balancing account entries shall be subject to review in the annual transition cost proceedings. For now, we will retain the filing date of June 1, 1998 for the first annual transition cost proceeding. While there will only be three or four months of recorded data, we should have additional information regarding market valuation and recalibrated amortization schedules. This first proceeding may be somewhat attenuated, but by addressing these issues early, we will be able to implement any required changes to our approach in a timely fashion. Thereafter, the annual transition cost proceedings should review recorded data on a calendar-year basis.

PG&E, Edison, and SDG&E should provide monthly reports of all entries to the transition cost balancing account, as well as the balances and returns used to develop transition cost revenue requirements, the assumptions used in estimating market value, the results of any actual market valuations, any changes in revenue requirements resulting from capital additions proceedings, changes in amortization schedules due to changes in market value estimates or actual market valuations, and any additional acceleration beyond the 48-month amortization schedule. We will also require a review of the entries to the must-run and non-must-run fossil memorandum accounts.

We will require that all cost and revenues related to Power Exchange and ISO revenues be justified and subject to an audit. We will review various costs which have been determined to be eligible for transition cost recovery, consistent with our findings in D.97-06-060 and this decision. For example, we will address the reasonableness of employee-related transition costs, purchased power contract administration, QF contract administration, geothermal contract administration, water purchases, and PG&E's WAPA true-up. In addition, we will consider the utilities' mitigation efforts regarding off-site common and general plant and will review the assessments of Edison's land assets surrounding its gas-fired fossil plants. We will also review such recorded costs as the losses associated with reacquired debt and other actual costs the utilities present for transition cost recovery. ECAC costs recorded through December 31, 1997 will continue to be considered in traditional reasonableness reviews. Finally, we reiterate our instructions to the utilities to seek authority for recovery of transition costs not considered in this decision by filing new applications, rather than advice letters. The advice letter process is inappropriate for requesting this sort of recovery.

20. Conclusion

We have reviewed the utilities' requests for a transition cost recovery for various assets, costs, and cost categories. Because we have discussed several complex issues in this decision, we summarize our findings here and in Attachments 3 and 4.

The utilities should track actual costs and revenues on a plant-specific basis for both must-run and non-must-run plants. Any excess revenues should be credited to the transition cost balancing account annually. The revenues accrued in the memorandum account will earn the reduced transition cost rate of return. No interest rate or rate of return will be applied to any debit balances in that account. The only instances in which we will consider transition cost recovery for must-run plants are for those particular units operating at particular times that plant is actually called upon for reactive power/voltage support (and not any other "must-run" purpose) and for which the ISO contract has not provided recovery of operating costs, and the units are otherwise authorized to recover market-based rates. It is possible that under proposed Agreement A, the utilities will not recover all operating costs from ISO revenues; however, the desired solution is for the utilities to negotiate to move to Agreement B, rather than receiving assured transition cost treatment. The utilities must clearly demonstrate that the units are necessary for reactive power/voltage support and that transition cost recovery is only for that period during which contract terms are adjusted approximately at the ISO. Proposed Agreement C does not allow for market-based rates and is based on cost-of-service; therefore, no transition cost recovery is permitted for units under this proposed contract. The memorandum accounts will allow the necessary tracking to occur so that any modifications to our procedures can be executed efficiently and easily.

We accept the auditors' findings regarding the net book value of plant assets as of December 31, 1995. As of January 1, 1998, the net book value as of December 31, 1995 should be amortized over the 48-month transition period, consistent with the requirements established in D.97-06-060. The net book value should account appropriately for accumulated depreciation and deferred taxes. As the capital additions proceedings are completed, we will allow adjustments to net book value to reflect our findings in these proceedings and to account for depreciation for 1996 and 1997.

The gain or loss resulting from sale of assets, including land, should flow through the transition cost balancing account. Any loss associated with sale of assets should be amortized over the transition period, but any gain should be credited to offset transition costs and close out the appropriate subaccount.

As of January 1, 1998, materials and supplies inventories are going forward costs. Unamortized materials and supplies balances should not earn a rate of return. A physical inventory of materials and supplies inventories should be undertaken as of December 31, 1997, or as close to that date as possible, and the fair market value of the inventory components should be assessed. In the alternative, the utilities may deem the book value of the December 31, 1997 materials and supplies inventories balances to equal their market value. The utilities should file these market value assessments in the applications to market value their retained assets, which shall be filed on March 2, 1998.

We will defer consideration of the transition cost recovery of fuel oil inventory pending the ISO's determination as to whether these inventories are necessary for system reliability. For 1998 only, the utilities may apply the 3-month commercial paper rate to the unamortized balance of the level of fuel oil inventories. In addition, Edison shall file a proposal to account for the revenue-sharing mechanism for revenues accruing from third-party transportation on its fuel oil inventory pipelines, consistent with D.94-10-044. This proposal shall be filed on March 2, 1998 as part of Edison's application to approve retained assets. Edison's gas inventories and coal inventories should be market valued as of December 31, 1997, similar to our findings for materials and supplies inventories. Replenishment of inventory levels after January 1, 1998 will not be eligible for transition cost recovery. Carrying costs should not be allowed on any unamortized difference between market and book value. In the alternative, Edison may deem the book value of the December 31, 1997 gas and coal inventories balances to equal their market value.

Environmental and non-environmental non-nuclear decommissioning costs should continue to be recovered at the level currently included in authorized rates. The accumulated decommissioning amortization should be accounted for as an offset to rate base, at least until such time as the generating plants are market valued, and should not be accelerated. The timing of environmental decommissioning should be accounted for in a net present value calculation, to the extent that environmental decommissioning is expected to occur after 2001. Hydroelectric negative net salvage should not be recovered as a separate item in the transition cost balancing account, but should be factored into PG&E's depreciation reserve.

CWIP costs incurred prior to December 31, 1995, which are not approved for recovery in separate capital additions proceedings for 1996 and 1997, and are not included in divestiture are not eligible for transition cost recovery. RWIP costs should continue to be treated as an increase to the accumulated depreciation reserve. After market valuation, ratepayers will no longer be responsible for additional costs associated with retiring a plant, including decommissioning. CWIP costs associated with past hydroelectric relicensing costs will be considered in the market valuation of hydroelectric assets.

The on-site common and general plant estimates should be amortized over the transition period, using the December 31, 1995 amounts which have been verified by the auditors. Off-site common and general plant assets are excluded from transition cost recovery at this time.

The sale of excess emissions credits results in a gain on sale of utility property which should be credited to the TCBA to offset transition costs.

Edison should prorate land according to its functions and should remove all land associated with generating assets to be divested from rate base upon the date of divestiture. Only the book value of land classified as generation and which Edison has proposed to divest with the underlying generating assets and land allocated to fuel oil pipelines shall be amortized through the transition cost balancing account at the reduced rate of return. We will defer ruling on land associated with fuel-oil pipelines until the ISO has made its determination regarding these assets, but Edison should address this land in its proposal to ensure that ratepayers continue to benefit from the revenue-sharing mechanism adopted in D.94-10-044. When Edison has completed its analysis confirming the pro-rata assignment of land to functions and the appraisal of land is completed, the transition cost balancing account shall be trued-up as appropriate. This analysis should be included in the March 2, 1998 filing. Land should be valued as of the date of divestiture, if not before, and the transition cost balancing account should be credited appropriately.

In conformance with FERC's classification of step-up transformers and generation radial-tie lines as generation assets, these assets should be eligible for transition cost recovery.

The fixed ICIP prices adopted for Diablo Canyon and SONGS 2&3 will be compared to the Power Exchange market-clearing price to determine ongoing transition cost recovery. Because of the balancing account treatment adopted in D.96-12-083, we will compare Palo Verde's incremental operating costs as billed by Arizona Public Service with the market-clearing price, rather than the fixed ICIP cost approach which we have implemented for Diablo Canyon ad SONGS 2&3. We will rely on the ICIP prices adopted in D.96-04-059 to compute any necessary transition cost recovery or offsets.

PG&E's and SDG&E's requests for fixed costs related to fuel and fuel transportation contracts are denied. Other than the exceptions provided Edison, fuel and fuel transportation costs are going forward costs not eligible for recovery in the transition cost balancing account. Edison's fuel costs should be recovered from market revenues, to the extent possible. The uneconomic portion of Edison's fixed costs of its fuel and fuel transportation contracts must be calculated by comparing fixed costs to the market-clearing price for natural gas fuel and transportation.

Transition cost recovery of QF contract costs and interutility contract costs will be based on actual per-kilowatt-hour costs incurred compared to the Power Exchange market-clearing price. Each utility should establish subaccounts in its transition cost balancing account to track QF contract costs, interutility contract costs, BRPU settlement costs, and QF contract restructurings and buyouts.

The revenue requirements established for hydroelectric and geothermal assets should be based on the net book value adopted in these proceedings. Market revenues earned for hydroelectric and geothermal assets should be tracked in a memorandum account and compared to the revenue requirements established for these assets, and excess revenues should be credited to offset transition cost recovery. The reduced rate of return should apply to hydroelectric and geothermal assets, which should be recovered in the transition cost balancing account. Market revenues in excess of revenue requirements should be credited to the transition cost balancing account on an annual basis. Similar to the memorandum accounts established for the fossil must-run and non-must-run plants, any excess revenues accruing in a particular month will earn the reduced transition cost rate of return, rather than the commercial paper rate. No interest rate or rate of return will be applied to any debit balances in that memorandum account.

Costs associated with employee benefits must be included in current operating costs and recovered from market revenues for all such generation-related expenses accrued <u>after</u> January 1, 1998. Because PG&E accounts for workers' compensation on a "pay-as-you-go" basis, rates include costs that would have also been included in the actuarial calculation for post-1998 obligations of the workers' compensation regulatory asset. PG&E's request for transition cost recovery of workers' compensation costs is denied.

Because we have approved accrual accounting treatment for the long-term disability obligation and we can establish a cut-off point for going forward costs, this obligation is eligible for transition cost recovery. Transition cost recovery is authorized for Edison's post-employment benefits associated with claims prior to 1998. No rate of return should apply to the unamortized balance. PG&E's post-employment benefits should be accounted for similarly to Edison's and the initial obligation as established in D.95-12-055 should be amortized over the transition period. No rate of return should be applied to the unamortized balance.

The PBOP regulatory assets and transition obligations are eligible for transition cost recovery and should be amortized ratably over the transition period, based on the December 31, 1997 estimates which represent actuarial determinations with no rate of return applied to the unamortized balance. For PG&E, it is reasonable to apply the discount rate of 9% that was adopted in D.95-12-055. These accelerated amounts are to be placed in the appropriate trust funds for each utility; to the extent they are not so deposited, these amounts will be treated as a rate base offset with a corresponding credit to the transition cost balancing account. We will allow a tax gross-up only to the extent these contributions to the trust are tax deductible. PBOP amounts should not be contributed to the trusts until they are tax-deductible. Any money which is collected but not yet contributed then becomes a rate base offset, which is reduced by deferred taxes associated with the asset for the taxes due when the money is collected. Edison's estimates of costs related to Mohave coal mine employees for PBOP expenses are denied transition cost recovery at this time.

For pensions, the regulatory asset, consisting of the pension transition obligation, should be offset by the pension regulatory liabilities. The net regulatory liability should then be credited to offset transition cost recovery. For PG&E, pensions are overfunded and no tax-deductible contributions have been made recently. It is reasonable to require PG&E to repay the pension transition obligation with the overfunded amounts, rather than increasing transition cost recovery unnecessarily. We will exclude SDG&E's claim for its pension regulatory asset from transition cost recovery, but it is reasonable to allow SDG&E to demonstrate that its pension is under-funded in the annual transition cost proceeding.

The environmental compliance regulatory asset is a forecast of costs to be incurred on the same activities included in the HSM. These activities do not include those associated with generating plant. The costs recorded in the environmental compliance regulatory asset are speculative and should be excluded from transition cost recovery unless actually incurred during the transition period. If the utilities incur environmental compliance costs for generation-related projects, PG&E, Edison, and SDG&E may seek recovery in the annual transition cost proceedings.

We will allow transition cost recovery for actual losses incurred to reacquire debt and preferred stock, net of gains, and will review these costs in the annual transition cost proceedings. We will require the utilities to make a showing in the annual transition cost proceedings to demonstrate that adequate ratemaking safeguards have been implemented to ensure that the savings in the embedded cost of debt are adequately accounted for and that no double-counting has occurred.

Transition cost taxes (regulatory tax receivables) are fully eligible for recovery during the transition period. All property-related regulatory tax assets and payables will be amortized to zero by the end of the transition period, which will settle all property-related tax benefits or obligations, except as provided for the nuclear generating facilities in D.97-05-088, D.96-12-083, and D.96-01-011 and D.96-04-059.

1997 ECAC and ERAM balances should be transferred to the transition cost balancing account, in conformance with D.96-12-077.

PG&E may amortize its WAPA regulatory asset or liability based on trued-up December 31, 1995 amounts. PG&E must support its December 31, 1997 calculations in the annual transition cost proceeding. PG&E's QF buyout regulatory asset should not receive transition cost recovery until these amounts are determined to be reasonable.

The reduced rate of return should apply to non-nuclear generation assets currently in rate base and eligible for transition cost recovery, except as described in this decision, beginning on the date on which the utilities established the memorandum accounts provided for in D.97-07-059. The reduced rate of return for non-nuclear generating assets shall be calculated based on the embedded cost of debt adopted in D.96-11-060. PG&E's reduced rate of return for transition cost purposes is 7.13%; Edison's reduced rate of return is 7.22%; and SDG&E's reduced rate of return is 6.75%. The embedded cost of debt shall remain fixed for the entire term of the transition period or relevant amortization period, irrespective of whether the utility's cost of debt changes.

Using a market-based approach to transition cost recovery is consistent with the law and preferable from our policy standpoint. The next step, and the most important step for purposes of determining the economic or uneconomic portion of these categories, is market valuation. Ensuring that market valuation occurs soon in the transition period is essential to the final determination of transition cost recovery for those assets subject to market valuation, will ensure that transition cost recovery is expeditious and orderly, and will eliminate the burdensome tracking requirements that must exist until this occurs. To expedite this process, we order PG&E, Edison, and SDG&E to file applications no later than March 2, 1998 to establish the principles necessary to appraise their retained assets. PG&E, Edison, and SDG&E should file separate applications no later than March 31, 1998, to provide for review of the restructuring implementation costs, addressed in § 376. Although we have previously considered the possibility that these issues would be consolidated in Phase 3 of these proceedings, we will now require separate applications. This approach will facilitate our decision-making process and lead to more efficient resolution of these issues.

To implement the findings in this decision, PG&E, Edison, and SDG&E are directed to finalize their transition cost balancing account tariffs. PG&E, Edison, and SDG&E shall file compliance advice letters by December 12, 1997, which shall be effective as of January 1, 1998, unless the Energy Division determines that these tariffs are not in compliance with this decision. These final tariffs shall incorporate the findings addressed in this decision, including the elimination of various categories for transition cost recovery, the implementation of placeholders for others, and, depending on the category, identifying the applicable rate of return, commercial paper rate, or no interest rate as appropriate.

Transition cost balancing account pro forma tariffs have been the subject of various workshops convened by the Energy Division. The most recent round of workshops was held on August 26, 27, and 28, 1997. The Energy Division issued its workshop report on September 16. Comments on the workshop report were filed on September 25. Several issues were raised in the workshop report which are not addressed herein, and will be addressed in a separate decision issued before the end of the year. Parties will be afforded the opportunity to comment on that decision.

21. Comments on Proposed Decision

PG&E, Edison, SDG&E, ORA, TURN, DOD, EPUC, and Enron filed timely comments on the proposed decision.[27] PG&E, Edison, SDG&E, CIU (jointly with CLECA, CMA, and Farm Bureau), ORA, TURN, and Enron filed reply comments.

We have incorporated these comments throughout the decision as appropriate. 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.

Findings of Fact

1. The need for forecasts of transition cost amounts is eliminated by the rate freeze and the residual calculation of the CTC.

[27] Gordon Allot, Esquire also filed comments. Mr. Allot is not a party to this proceeding, nor did he request to participate in these proceedings, in accordance with either Rule 53 or Rule 54 of our Rules of Practice and Procedure. We will therefore not consider Mr. Allot's comments. Furthermore, we note that one of Mr. Allot's arguments appears to be a broad challenge to the statute itself and are thus not relevant to the particulars of the instant proceeding. Administrative agencies, including this Commission, cannot determine the constitutional validity of any statue. (Constitution of the State of California, Article III, § 3.5.)

2. The assessment of whether assets and costs are economic or uneconomic must be made on an asset-specific basis.

3. If a generation facility is likely to be economic on an overall basis, specific costs associated with that plant will not be eligible for treatment as transition costs.

4. A careful tracking of eligible transition costs and accrued revenues is necessary to ensure that we can confidently track recovery on an asset-specific basis.

5. Net book value is defined as original cost less accumulated depreciation and amortization in determining eligibility of various costs and cost categories for transition cost recovery, including an appropriate accounting of the impact of deferred taxes on the net book value quantification.

6. Sunk costs are defined as undepreciated capital costs and costs which have already been incurred and cannot be avoided or reduced.

7. Going forward costs are defined as all costs necessary for the continued operation of the plant or unit, both variable and fixed.

8. It is premature to adopt an implementation methodology for the 150 basis point mechanism at this time, since no utility is claiming this incentive for its must-run plants.

9. All going forward costs must be recovered from market revenues before such incentive mechanisms as the 150 basis point mechanism may be applied.

10. Market mechanisms are preferable to administrative calculations of transition costs.

11. The utilities should establish memorandum accounts to track on a monthly basis actual going forward costs and market revenues on a plant-specific basis for both must-run and non-must-run plants. Any excess revenues should be credited to the transition cost balancing account on an annual basis. The revenues accrued in the memorandum account will earn the reduced transition cost rate of return. No interest rate or rate of return will be applied to any debit balances in that account.

12. The only instances in which we will consider transition cost recovery for must-run plants are for those particular units operating at particular times when the ISO calls on the plant for reactive power/voltage support (and not any other "must-run"

purpose) and for which the ISO contract has not provided recovery of operating costs, and the units are otherwise authorized to recover market-based rates.

13. It is possible that under proposed Agreement A, the utilities will not recover all operating costs from ISO revenues for the first 90 days of the transition period.

14. Proposed Agreement C does not allow for market-based rates and is based on cost-of-service; therefore, no transition cost recovery is permitted for units under this proposed contract.

15. The memorandum accounts we order will allow the necessary tracking to occur so that any modifications to our procedures can be executed efficiently and easily.

16. We have prescribed various guidelines in D.97-06-060 regarding order of recovery and acceleration, and have also stated that each asset should be depreciated to its market value, but not below, and that recalibration of the amortization may then be necessary. These guidelines will adequately capture the economic value of depreciation.

17. Market valuation allows us to obtain important information regarding economic and uneconomic costs for generating assets and assists us in determining if the rate freeze may end prior to March 31, 2002.

18. We accept the auditors' findings regarding the net book value of plant assets as of December 31, 1995.

19. As of January 1, 1998, the net book value of the fossil generating plants as of December 31, 1995 should be amortized over the 48-month transition period. The net book value should account appropriately for accumulated depreciation and deferred taxes. As the capital additions proceedings are completed, we will allow adjustments to net book value to reflect our findings in these proceedings and account for depreciation accrued in 1996 and 1997. The utilities may adjust the transition cost balancing account when assets are sold or market-valued to reflect the actual costs on the books. If decisions regarding capital additions are issued after the sale of a plant, the transition cost balancing account will be adjusted to reflect the outcome of those proceedings.

20. The gain or loss resulting from sale of assets, including land, should flow through the transition cost balancing account.

21. Any loss associated with sale of assets should be amortized over the transition period, but any gain should be credited to offset transition cost recovery and close out the appropriate subaccount.

22. The audit was conducted according to the directives of the August 1, 1996, assigned Commissioner Ruling and the audit procedures outlined in the auditors' workplan.

23. As of January 1, 1998, materials and supplies inventories are going forward costs.

24. Unamortized materials and supplies balances should not earn a rate of return.

25. A physical inventory of materials and supplies inventories should be undertaken as of December 31, 1997 or as close to that date as possible, and the fair market value of the inventory components should be assessed. In the alternative, the utilities may deem the book value of the December 31, 1997 materials and supplies inventories balances to equal their market value.

26. Allowing the difference between market value and cost of materials and supplies inventories as of December 31, 1997 to be eligible for transition cost treatment allows for a cohesive treatment of divestiture and transition cost recovery.

27. If the utilities deem the book value of the December 31, 1997 materials and supplies balances to equal their market value, the utilities should track the difference between the physical inventories existing as of December 31, 1997 and the physical inventories existing as of the date of actual market valuation. Changes in inventory levels are going forward costs and are not eligible for transition cost recovery.

28. It is appropriate to defer consideration of the transition cost recovery of fuel oil inventory pending the ISO's determination as to whether these inventories are necessary for system reliability.

29. For 1998 only, the utilities may apply the 3-month commercial paper rate to the unamortized balance of the level of fuel oil inventories.

30. For gas and coal inventories, it is reasonable to establish a bright line for determining uneconomic costs up to January 1, 1998 and going forward costs after that date. Thus, Edison should undertake a physical inventory of its gas and coal inventories

as of December 31, 1997, or as close to that date as possible, and the fair market value of the inventories should be assessed. Alternatively, Edison may deem the book value equal to the market value for gas and coal inventories.

31. It will be relatively simple to compare the market price of gas with the net book value of Edison's gas inventory.

32. The value of coal is not based on transporting it to a different site, but rather on its intrinsic market value.

33. If Edison deems the book value of the December 31, 1997 gas and coal inventory balances to equal their market value, Edison should track the difference between the physical inventories existing as of December 31, 1997 and the physical inventories existing as of the date of actual market valuation. Changes in inventory levels are going forward costs and are not eligible for transition cost recovery.

34. Replenishment of inventory levels after January 1, 1998 will not be eligible for transition cost recovery. Carrying costs should not be allowed on any unamortized difference between market and book value.

35. The HSM recovers costs that are not already recovered in rates, whereas environmental decommissioning is recovered in current rates through the decommissioning expense.

36. Because it is not probable that the environmental decommissioning responsibility can be transferred to new owners, we will allow the unrecovered portion of these costs, as currently authorized in rates, to be amortized as a current cost in the transition cost balancing account.

37. Environmental decommissioning costs will be accounted for as a rate base offset, as these costs are accumulated prior to being spent.

38. We will require appropriate true-ups and credits to the transition cost balancing account to reflect updated studies of environmental decommissioning costs, actual costs incurred, any transfer of this obligation to new owners, and any change in the method of recovery of these costs deemed appropriate by this Commission at the time of market valuation.

39. The market valuation process for both divested and retained plants will yield more accurate and useful values of non-nuclear non-environmental decommissioning costs than will an estimate of what these expenditures are likely to be.

40. Non-environmental non-nuclear decommissioning costs should continue to be recovered at the annual level currently included in authorized rates and amortized beginning January 1, 1998.

41. The accumulated decommissioning amortization should be accounted for as an offset to rate base, at least until such time as the generating plants are market valued.

42. There is no need for accelerated depreciation of the non-nuclear decommissioning expense, because the non-environmental amounts will be reflected in the market valuation process.

43. At the time of market valuation, amounts collected for both environmental and non-environmental decommissioning may be credited against liabilities for either decommissioning category.

44. It is not reasonable to treat fossil decommissioning costs as if all such costs will be incurred by 2001.

45. For plants retired before or during the transition period, true-ups should be made to the transition cost balancing account for actual decommissioning work (both environmental and non-environmental) and revised decommissioning studies. These costs will be reviewed in the annual transition cost proceeding.

46. The timing of decommissioning should be accounted for in a net present value calculation, to the extent that environmental decommissioning is expected to occur after 2001.

47. Hydroelectric negative net salvage should not be recovered as a separate item in the transition cost balancing account, but should be factored into PG&E's depreciation reserve.

48. The CWIP account includes costs for projects which were under construction prior to December 31, 1995.

49. CWIP costs incurred prior to December 31, 1995, which are not approved for recovery in separate capital additions proceedings are not eligible for transition cost

recovery. However, any CWIP remaining on the date a generation station is sold to a new owner should be reflected in both the book and market values of that station.

50. RWIP costs should continue to be treated as an increase to the accumulated depreciation reserve.

51. After market valuation is finalized for each plant, ratepayers will no longer be responsible for any additional costs associated with retiring a plant, including decommissioning costs not addressed in the market valuation process.

52. Common plant is defined as those assets associated with more than one utility service, such as gas and electricity.

53. General plant includes several categories of costs not assignable to more specific accounts.

54. On-site common and general plant is generation-related assets that are integral to the operation of the generating plant.

55. It is reasonable to allow amortization of the on-site common and general plant recorded amounts at the December 31, 1995 levels which have been verified by the auditors.

56. The market valuation process should capture the value of on-site common and general plant assets.

57. The majority of items in the category of off-site common and general plant assets will likely be usable in other functions and should be excluded from transition cost recovery.

58. Emission trading credits are used by the utilities to offset certain air pollution emissions under a program established by federal statute.

59. Excess emission trading credits are those not needed by the utilities and can be bought and sold in a secondary market.

60. The sale of excess emissions credits results in a gain on utility property which should be refunded to ratepayers either through credits to the transition cost balancing account or as an offset to net eligible transition costs.

61. PG&E and Edison should include proposals in the divestiture proceedings for computing and applying the increase in the reduced rate of return applicable to the

non-nuclear and non-hydroelectric equity components, of up to 10 basis points for each 10% of fossil generating capacity divested.

62. PG&E and Edison should establish tracking accounts to track the differential in the non-nuclear and non-hydroelectric equity component of the reduced rate of return as each 10% of fossil generating capacity is divested, which would then be applied to the reduced rate base.

63. Edison should prorate land according to its functions and should remove all land associated with divested generating assets from rate base upon the date of divestiture.

64. Only the book value of land which has been classified as generation and which Edison has proposed to divest with the underlying generating assets should be amortized through the transition cost balancing account at the reduced rate of return.

65. Land associated with transmission-related plant should not impact transition cost recovery and should continue to earn the authorized rate of return.

66. Land which is not included with divestiture and which is not allocated to fuel oil pipelines should be excluded from transition cost recovery at this time.

67. When Edison has completed its analysis confirming the pro-rata assignment of land to functions and the appraisal of land is completed, the transition cost balancing account should be trued-up as appropriate. Edison should present its pro-rata analysis to this Commission in the March 2, 1998 appraisal application.

68. It is reasonable to calculate the fair market value of all land associated with generation assets upon the date of divestiture, if not before, other than land associated with transmission plant and fuel-oil pipelines. The transition cost balancing account should be credited appropriately.

69. FERC has classified step-up transformers and generation radial-tie lines as generation assets and these assets should be eligible for transition cost recovery.

70. Edison's retrofits to SONGS' low pressure turbines increased plant safety and reliability and were not undertaken to increase capacity per se.

71. An increase in produced kilowatt hours has the potential to increase claimed transition costs if the Power Exchange price is less than the forecasted ICIP price.

Similarly, if the Power Exchange price is greater than forecasted ICIP prices, the increase in production has the potential to offset transition costs.

72. We will rely on the ICIP prices adopted in D.96-04-059 to compute any necessary transition cost recovery or offsets. Each kilowatt hour will continue to receive the ICIP price and will be compared with the Power Exchange market clearing price. Edison should incorporate this methodology in its final transition cost balancing account tariffs.

73. We will not allow Edison to track fuel contract and transportation costs that we have not yet determined to be reasonable through the transition cost balancing account.

74. Other than for the exceptions provided Edison, fuel and fuel transportation costs are going forward costs that are not eligible for recovery in the transition cost balancing account.

75. Edison's fuel costs, including coal reclamation and closure costs, should be recovered from market revenues, to the extent possible.

76. The uneconomic portion of Edison's costs of its fuel and fuel transportation contracts must be calculated by comparing costs to market revenues.

77. Edison's fuel and fuel transportation contract costs should be tracked in a memorandum account, until they are determined to be reasonable by this Commission.

78. Transition cost recovery of QF contract costs and interutility contract costs will be based on actual incurred costs compared to the Power Exchange market clearing price. As used in this context, the Power Exchange market-clearing price is equal to the day-ahead energy price and/or the price of ancillary services which can be economically provided through the contract.

79. The annual transition cost proceedings should include a review of QF contract administration and litigation costs.

80. Each utility should establish placeholder subaccounts in its transition cost balancing account to track QF contract costs, interutility contract costs, BRPU settlement costs, and QF contract restructurings and buyouts.

81. The generation PBR proceeding (A.96-07-009 *et al.*) has been modified to establish revenue requirements for PG&E's hydroelectric and geothermal assets and Edison's hydroelectric assets.

82. Certain issues associated with must-run hydroelectric plants and reasonableness of pumped storage costs will be considered in A.96-07-009 *et al.*

83. The revenue requirements established for hydroelectric and geothermal assets should be based on the net book value adopted in these proceedings.

84. Market revenues earned for hydroelectric and geothermal assets should be tracked in a memorandum account and compared to the revenue requirements established for these assets. Market revenues in excess of revenue requirements should be credited to the transition cost balancing account on an annual basis. Similar to the memorandum accounts established for the fossil must-run and non-must-run plants, any excess revenues accruing in a particular month will earn the reduced transition cost rate of return. No interest rate or rate of return will be applied to any debit balances in that memorandum account.

85. The reduced rate of return should apply to hydroelectric and geothermal assets, which will be recovered in the transition cost balancing account.

86. Costs associated with pumped storage assets should be recovered in the transition cost balancing account.

87. Employee benefits are tracked either by accrual accounting or the "pay as you go" method.

88. Accrual accounting occurs when the utility recognizes the costs of benefits as they are earned or attributed to an employee, as services are provided. For financial reporting purposes, utilities account for PBOPS, pension, workers compensation, and long-term disability benefits on an accrual basis.

89. Under "pay as you go" accounting, a utility recognizes an employee benefit cost when it actually pays such a benefit to the employee.

90. Costs associated with employee benefits must be included in current operating costs and recovered from market revenues for all such generation-related expenses accrued after January 1, 1998.

91. Because PG&E accounts for workers' compensation on a "pay-as-you-go" basis, rates include costs that would have also been included in the actuarial calculation for post-1998 obligations of the workers' compensation regulatory asset.

92. It is not reasonable to allow PG&E's workers' compensation regulatory asset to receive transition cost treatment at this time because of the potential for double recovery and the commingling of pre-1998 and post-1998 costs.

93. Because we have approved accrual accounting treatment for this obligation and we can establish a cut-off point for going forward costs, the long-term disability obligation is eligible for transition cost recovery.

94. It is reasonable to adopt the joint proposal by Edison and TURN regarding Edison's post-employment benefits.

95. Transition cost recovery is authorized for Edison's post-employment benefits associated with claims prior to 1998. No rate of return should apply to the unamortized balance.

96. PG&E's long-term disability obligation should be accounted for similarly to Edison's, and the initial obligation as established in D.95-12-055 should be amortized over the transition period. No rate of return should be applied to the unamortized balance.

97. The PBOP regulatory asset represents estimated costs for medical and life insurance benefits attributed to employee service which has accrued since 1993.

98. The PBOP transition obligation represents costs for benefits attributed to employee service which occurred prior to 1993.

99. The PBOP regulatory assets and transition obligations are eligible for transition cost recovery and should be amortized ratably over the transition period.

100. The PBOP regulatory assets and transition obligations should be amortized based on the December 31, 1997, estimates which represent actuarial determinations with no rate of return applied to the unamortized balance.

101. If post-retirement benefit plans are modified to reduce benefits during the transition period, which then reduces the actuarial basis of the transition obligations,

these true-ups should be accounted for as credits to the transition cost balancing account during the transition period.

102. For PG&E, it is reasonable to apply the discount rate of 9% which was adopted in D.95-12-055.

103. PBOP amounts should not be contributed to the trusts until they are tax-deductible. Any money which is collected but not yet contributed then becomes a rate base offset, which is reduced by deferred taxes associated with the asset for the taxes due when the money is collected.

104. Edison's estimates of costs related to Mohave coal mine employees for PBOP expenses are precluded from transition cost recovery at this time.

105. Under cost-of-service ratemaking, pension payments are recognized to the extent they are tax-deductible under Federal rules, while, under financial reporting, expenses are calculated on an actuarial basis.

106. Pension contributions are deductible only for tax purposes if amounts must be contributed to pension funds to ensure that adequate funds are available to pay benefits.

107. The pension transition obligation is amortized in rates, but is not a recorded regulatory asset.

108. The unrecognized pension transition obligation is an obligation established in the past to correct prior pension underfunding, in equal amounts, without interest.

109. The regulatory asset, consisting of the pension transition obligation, should be offset by the pension regulatory liabilities. The net regulatory liability should then be credited to offset transition cost recovery.

110. For PG&E, pensions are over-funded and no tax-deductible contributions have been made recently.

111. It is reasonable to require PG&E to repay the pension transition obligation with the over-funded amounts, rather than increasing transition cost recovery unnecessarily.

112. We will exclude SDG&E's claim for its pension regulatory asset from transition cost recovery, but it is reasonable to allow SDG&E to demonstrate that its pension is under-funded in the annual transition cost proceeding.

113. The environmental compliance regulatory asset is a forecast of costs to be incurred on the same activities included in the HSM. These activities do not include those associated with generating plant.

114. The costs recorded in the environmental compliance regulatory asset are speculative and should be excluded from transition cost recovery unless actually incurred during the transition period.

115. If the utilities incur environmental compliance costs for generation-related projects during the transition period, PG&E, Edison, and SDG&E may seek recovery in the annual transition cost proceedings.

116. Future costs related to reacquired debt and preferred stock may arise as a result of the utilities' reducing debt and preferred stock levels in their respective capital structures.

117. The embedded cost of debt includes a component to pay for unamortized debt discounts and these costs should not be eligible for transition cost recovery.

118. We will allow transition cost recovery for actual losses incurred to reacquire debt and preferred stock, net of gains, and will review these costs in the annual transition cost proceedings.

119. We will require the utilities to make a showing in the annual transition cost proceedings to demonstrate that adequate ratemaking safeguards have been implemented to ensure that the savings in the embedded cost of debt are adequately accounted for and that no double-counting has occurred.

120. Transition cost taxes (regulatory tax receivables) are fully eligible for recovery during the transition period.

121. All property-related regulatory tax assets and payables will be amortized to zero by the end of the transition period, which will settle all property-related tax benefits or obligations, except as provided for the nuclear generating facilities in D.97-05-088, D.96-12-083, and D.96-01-011 and D.96-04-059.

122. ECAC and ERAM balances as of December 31, 1997 may be transferred to ITCBA or to the transition cost balancing account. The ITCBA should then be transferred to the TCBA.

123. An audit is necessary to verify the transfer of balances in the TCBA, to review the balances in the ECAC and ERAM balancing accounts, and to ensure that all headroom revenues are properly credited to the TCBA.

124. It is reasonable to allow PG&E to amortize its WAPA regulatory asset or liability based on trued-up December 31, 1995 amounts. PG&E must support its December 31, 1997 calculations in the annual transition cost proceeding.

125. PG&E's QF buyout regulatory asset should not receive transition cost recovery until these amounts are determined to be reasonable.

126. SDG&E's abandoned projects regulatory asset and AMAX coal contract buyout regulatory asset are eligible for transition cost recovery.

127. The necessary components of transition cost recovery are in place and the utilities' risk of recovery is decreased commensurately.

128. By beginning the rate freeze on January 1, 1997, we have allowed the utilities to accrue revenues that may serve to offset transition costs.

129. If the rate freeze had not begun on January 1, 1997, the ratepayers may have enjoyed the benefits of decreased rates.

130. The calculation of the reduced rate of return for non-nuclear generating assets should be based on the cost of debt adopted for each utility in the 1997 cost of capital decision, D.96-11-060.

131. For the nuclear generating plants, the reduced rate of return should be consistent with that adopted in D.96-01-011 and D.96-04-059 for SONGS 2&3, D.96-12-083 for Palo Verde, and D.97-05-088 for Diablo Canyon.

132. We will retain the filing date of June 1, 1998 for the first annual transition cost proceeding.

Conclusions of Law

1. The notice requirement of § 370 does not require a specific forecast of transition costs, but rather the notification that such charges will be assessed.

2. PU Code § 367 gives utilities the opportunity to recover transition costs that are identified and determined by this Commission.

3. Our goal is to provide the utilities with a fair opportunity for full recovery of transition costs and to ensure that recovery of going forward costs is appropriately limited, consistent with the law.

4. The netting calculation required by § 367(b) does not preclude asset-by-asset transition cost tracking. The expeditious, orderly recovery of transition costs, as required by § 330 (t), requires this approach.

5. Section 367 includes generation-related regulatory assets and obligations as cost categories eligible for transition cost recovery. These costs cannot be excluded from such recovery, based on the definition of net book value for fossil assets.

6. Section 367(c)(1) refers specifically to particular plants or units providing reactive power/voltage support at particular times; we use this meaning in referring to must-run plants.

7. In D.97-04-042 and D.97-07-037, we determined that the 150 basis point incentive mechanism referred to in the Preferred Policy Decision applies only to must-run plants.

8. It is unlawful under § 367(c) to allow recovery of going forward costs through the transition cost balancing account.

9. The Legislature has stated that competition in electric generation is preferred to regulation, because it encourages innovation, efficiency, and better service from all market participants.

10. Market revenues from all sources which are in excess of costs should offset transition costs, as required by the Preferred Policy Decision and AB 1890.

11. It is not reasonable for the utilities to seek additional recovery through the transition cost balancing account for operating costs related to must-run units, to the extent the ISO limits payments to plants or units providing reactive power/voltage support.

12. Units and plants that operate under proposed Agreement C will not be eligible for transition cost treatment under § 367(c)(1).

13. The utilities must clearly justify transition cost recovery for operating costs for plants being operated for reactive power/voltage control purposes under Agreement A for the first 90 days of the transition period.

14. All non-nuclear generating assets are subject to market valuation by the end of 2001, as required by § 367(b). Nothing in AB 1890 prevents us from requiring market valuation to occur before the end of 2001.

15. It is reasonable to allow recovery of sunk costs associated with must-run units, because it is unlikely that any ISO call contract will recover all previously expended capital costs.

16. This Commission must make the final determinations regarding the eligibility of assets and cost categories for transition cost recovery.

17. It is not appropriate to allow the utilities to carry forward existing materials and supplies inventory into the new market, which could confer a competitive advantage on the utilities.

18. It is reasonable to appraise the market value of the materials and supplies inventories prior to divestiture and prior to our enactment of rules and procedures related to appraisal of retained generating assets, such as fossil-fired plants.

19. Deferring market valuation of inventories until the associated plant is either market valued or sold would allow changes in fuel inventory levels after January 1, 1998 to receive transition cost treatment.

20. Because the transition cost balancing account itself will be subject to the commercial paper rate of interest, there is no need to apply an additional interest rate calculation on those elements which would earn such a rate.

21. D.97-08-056 prohibits the utilities from entering any costs associated with generation into their HSM accounts.

22. In accordance with state and federal law, the utilities remain liable for contamination on power plant property.

23. CWIP costs incurred prior to December 31, 1995 which are not approved in separate capital additions proceedings do not meet the guidelines established for abandoned plant recovery.

24. Traditional ratemaking has provided that plant which is retired before the end of its useful life may continue to be depreciated, but does not earn a rate of return.

25. In D.95-12-051 and D.95-04-076, we generally found that the total net value of excess emissions credits should be returned to ratepayers.

26. Excess emissions credits do not fit the criteria established in D.96-12-025 regarding refunds made directly to ratepayers.

27. Accounting for excess emission credits through offsets to transition cost recovery conforms to the netting process established by § 367(b) and is consistent with our preference for market-based mechanisms.

28. Divestiture and other forms of market valuation are required by §§ 330(*l*)(2) and 367(b), to mitigate market power concerns and to transition utilities from regulated to unregulated status.

29. Sections 330 and 367 require a netting of all "above-market" and "below-market" transition cost assets to determine the costs to be recovered. Section 330 also requires that the transition to a competitive market be orderly, allow a fair opportunity to fully recover the costs associated with commission-approved generation-related assets and obligations, and be completed as expeditiously as possible. These two mandates demonstrate our duty to ensure that the market valuation process is structured to obtain maximum value of the property.

30. Pursuant to the Preferred Policy Decision and AB 1890, the ongoing ICIP costs, are compared to the market clearing price, and the difference between revenues and costs are either credited or debited, as appropriate, to the transition cost balancing account.

31. Because of the balancing account treatment adopted in D.96-12-083, we will compare Palo Verde's incremental operating costs as billed by Arizona Public Service with the Power Exchange market-clearing price.

32. It is not reasonable to interfere, in this decision, with the balance of risk and rewards that was adopted for the ratemaking treatment of SONGS 2&3.

33. Pursuant to § 367(c)(2), Edison may recover 100% of the uneconomic fixed costs of fuel and fuel transportation contracts, if these contracts were executed prior to December 20, 1995 and if the costs are determined to be reasonable by this Commission.

34. PG&E's and SDG&E's requests for transition cost recovery for fuel and fuel transportation costs should be denied, because they are not consistent with the exceptions delineated in § 367(c)(1) and 367(c)(2).

35. Section 367 affirms the Preferred Policy Decision's finding that the utilities are authorized to collect the ongoing transition costs resulting from the differences between QF contract prices and the Power Exchange market-clearing price and between interutility contract prices and the Power Exchange market-clearing price.

36. It is reasonable to track excess revenues resulting from comparing the hydroelectric and geothermal costs with Power Exchange prices and assets to use these revenues to offset transition cost recovery.

37. Hydroelectric and geothermal assets are subject to market valuation, pursuant to § 367(b).

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

39. We established regulatory asset treatment for PBOPs in D.91-07-006 and D.92-12-015.

40. In D.88-03-072, we declined to adopt SFAS 87 for ratemaking purposes. This decision applied to telephone carriers, but has been broadly applied to energy utilities.

41. It is not reasonable to increase transition costs because of phantom costs which may or may not occur in the future; the recovery of uncertain future costs is not allowed under § 367.

42. Pursuant to § 367, as amended by Senate Bill 477, and § 840(f), transition cost recovery should be allowed for future losses incurred to reacquire debt and preferred stock as of January 1, 1998.

43. The joint exhibit by PG&E, Edison, SDG&E, ORA, and TURN fairly resolves property-related tax issues, PG&E's vacation pay deferred tax asset, and Edison's ad valorem lien date tax asset.

44. It is equitable to allow transition cost treatment for both undercollections and overcollections accrued in the ECAC and ERAM balancing accounts as of December 31, 1997.

45. To the extent headroom is insufficient to address ECAC or ERAM undercollections, these amounts may not be carried over to later years for transition cost recovery, nor may such amounts be accumulated for later deferred collection.

46. In the Preferred Policy Decision, we established that it was reasonable to reduce the return on generation assets eligible for transition cost recovery by setting the return on equity at 90% of the embedded cost of debt.

47. The reduced rate of return is the appropriate measure of the reduced risk associated with these assets.

48. The Preferred Policy Decision provided for a 10-basis point increase in return on equity for each 10% of fossil plant divested.

49. With the recovery of generation plant-related transition costs, the utilities recover costs of plants that may no longer be used and useful in the new competitive marketplace.

50. It is the decreased business risk which triggers the application of the reduced rate of return, rather than accelerated depreciation.

51. The elements of transition cost recovery and the concomitant reduced risk were established when AB 1890 was signed into law and established that the utilities would have a reasonable opportunity collect uneconomic costs through the nonbypassable CTC.

52. It is reasonable to apply the reduced rate of return to generation assets currently in rate base and eligible for transition cost recovery, except as described in this decision, as of the date on which the utilities established the memorandum accounts provided for in D.97-07-059.

53. While D.96-04-059 addressed the broad applicability of the fixed 1995 cost of debt for purposes of the reduced return on equity, proper notice of this action was not provided and the parties' rights were impacted.

54. We adopted the 1996 embedded cost of debt for purposes of the reduced return calculation for Diablo Canyon in D.97-05-088.

55. The embedded cost of debt should remain fixed for the entire term of the transition period or relevant amortization period, irrespective of changes to each utility's cost of debt.

56. All transition cost balancing account entries are subject to review in the annual transition cost proceedings.

57. It is reasonable to review various costs that are eligible for transition cost recovery.

58. It is reasonable to consider the utilities' mitigation efforts regarding off-site common and general plant in the annual transition cost proceedings.

59. It is reasonable to review the assessments of Edison's land assets surrounding its gas-fired fossil plants.

60. This order should be effective today so that final transition cost balancing account tariffs may be implemented before January 1, 1998.

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 implement clear, straightforward language, which notifies the direct access customer of the obligation to pay transition costs in their respective tariffs.

2. PG&E, Edison, and SDG&E shall each establish a Power Exchange Revenue memorandum account and an Independent System Operator (ISO) Revenue memorandum account to track costs and revenues from all market sources for the non-must-run and must-run plants, respectively, as described in this decision. These memorandum accounts shall be reviewed in the annual transition cost proceedings and excess revenues shall be credited to offset transition costs on an annual basis. The revenues accrued in the memorandum account will earn the reduced transition cost rate of return. No interest rate or rate of return will be applied to any debit balances in those accounts.

3. PG&E, Edison, and SDG&E shall market value their respective materials and supplies inventories as of December 31, 1997 or as close to that date as possible. Transition cost recovery for materials and supplies inventory shall be allowed once that market valuation is completed according to the guidelines established in this decision, or by deeming the December 31, 1997 book value equal to market value for these inventories. PG&E, Edison, and SDG&E shall include these assessments in their March 2, 1998 applications for appraisal of retained assets.

4. Edison shall market value its gas and coal inventories as of December 31, 1997, or as close to that date as possible. For its gas inventories, Edison shall include this assessment in its appraisal application, as described in Ordering Paragraph 3. For its coal inventories, workshops will be held in the near future in the docket relating to Edison's application initiating market valuation by appraisal. Alternatively, Edison may deem the December 31, 1997 book value of its gas inventory balances and coal inventory balances equal to market value. In its appraisal application, Edison shall include a proposal for the treatment of fuel oil inventory which ensures that ratepayers continue to benefit from the revenue-sharing mechanism adopted in D.94-10-044.

5. With the exception of hydroelectric relicensing costs, to the extent that Construction Work in Progress (CWIP) costs incurred prior to December 31, 1995 are not approved in separate capital additions proceedings, or are not included in the plant balances being divested, PG&E's, Edison's, and SDG&E's requests for recovery of these costs are denied. Hydroelectric relicensing costs incurred prior to December 31, 1995 will be addressed in market valuation.

6. PG&E and Edison shall establish tracking accounts to track the differential in the non-nuclear and non-hydroelectric equity components of the reduced rate of return, as each 10% of fossil generating capacity is divested.

7. PG&E's and SDG&E's requests for transition cost recovery for fuel and fuel transportation costs are denied.

8. PG&E's request for transition cost recovery of the workers' compensation regulatory asset is denied at this time.

9. SDG&E's request for transition cost recovery for the pension regulatory asset is denied at this time.

10. Transition cost recovery of the environmental compliance regulatory asset is denied at this time.

11. The reduced rate of return shall be applied to generation assets currently in rate base and eligible for transition cost recovery, except as described in this decision, as of the date on which the utilities established the memorandum accounts provided for in Decision (D).97-07-059.

12. The reduced rate of return for non-nuclear generating assets shall be based on the embedded cost of debt adopted in D.96-11-060. For transition cost purposes, PG&E's reduced rate of return is 7.13%; Edison's reduced rate of return is 7.22%; and SDG&E's reduced rate of return is 6.75%.

13. The embedded cost of debt shall remain fixed for the entire transition period or relevant amortization period, irrespective of whether each utility's cost of debt changes.

14. PG&E, Edison, and SDG&E shall establish Transition Cost Balancing Accounts in compliance with the guidelines established in this decision, according to the following procedures:

a. PG&E, Edison, and SDG&E shall file compliance advice letters by December 12, 1997, which shall be effective as of January 1, 1998, unless the Energy Division determines that these tariffs are not in compliance with this decision.

b. The tariffs shall incorporate the findings addressed in this decision, including the elimination of various categories for transition cost recovery, the implementation of placeholders for others, and, depending on the category, identifying the applicable rate of return, commercial paper rate, or no interest rate, as appropriate.

c. PG&E, Edison,, and SDG&E shall file separate advice letters that detail the costs and revenues to be transferred to the transition cost balancing account as of January 1, 1998.

14. For the duration of the transition period, PG&E, Edison, and SDG&E shall provide monthly reports of all entries to the transition cost balancing account, as well as

the balances and returns used to develop transition cost revenue requirements, the assumptions used in estimating market value, the results of any actual market valuations, any changes in revenue requirements resulting from capital additions proceedings, changes in amortization schedules due to changes in market value estimates or actual market valuations, and any additional acceleration beyond the 48-month amortization schedule. These reports shall be submitted to the Energy Division and served on the parties to this proceeding. PG&E, Edison and SDG&E shall provide the Energy Division with three hard copies of each monthly report and an electronic version (on computer disk or via electronic mail) which contains each report and the underlying data, in either Word, Excel, or other format as specified by the Energy Division.

15. 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. All cost and revenues related to Power Exchange, ISO and other pertinent revenues must be justified and shall be subject to an audit.

16. As directed in D.97-06-060, 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.

17. In order to fully comply with Public Utilities Code § 367(b), PG&E, Edison, and SDG&E shall file applications no later than March 2, 1998 to establish the principles necessary to appraise their retained assets and to report assessments of the materials and supplies inventories, and, for Edison, the fuel inventories. As described in this decision, Edison shall include a proposal to ensure that ratepayers continue to benefit from the revenue-sharing mechanism for fuel oil inventory, adopted in D.94-10-044. Edison shall also include, in this application, its pro-rata analysis of its land, according to its function, i.e., transmission-related, fuel oil pipeline-related, and generating plant-

related, as well as Edison's proposal for treatment of fuel-oil pipeline land that is consistent with D.94-10-044.

18. In order to address restructuring implementation costs, pursuant to Public Utilities Code § 376, PG&E, Edison, and SDG&E shall file separate applications no later than March 31, 1998 to identify these costs.

19. The Energy Division shall oversee an audit of the balances transferred to the transition cost balancing account and the headroom revenues. The Energy Division may select independent auditors to undertake this audit, as described in this decision. The audit report shall be filed by December 31, 1998 and served on the service list to the first annual transition cost proceeding.

This order is effective today.

Dated November 19, 1997, at San Francisco, California.

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

I will file a concurring opinion.

/s/ JESSIE J. KNIGHT, JR.
Commissioner

ATTACHMENT 1
REQUEST FOR PLANT RELATED TRANSITION COSTS
INCURRED AS OF DECEMBER 31, 1995(1)
(Dollars in Thousands)

DESCRIPTION	PG&E	EDISON	SDG&E	TOTAL
Plant in Service				
Generation	4,799,488	2,832,717	429,532	8,061,737
Generation Related Transmission	265,202	48,728	5,772	319,702
General and Common Plant	83,076	42,929	4,388	130,393
Land and Land Rights	42,494	18,777	5,844	67,115
Intangibles	47,373	6,344	168	53,885
Other			16	16
Helms Regulatory Asset	14,593			14,593
Total Plant Investment	5,252,226	2,949,495	445,720	8,647,441
Reserves for Depreciation				
Accumulated Provision	(2,367,903)	(1,876,714)	(315,812)	(4,560,429)
Decommissioning Accrual	(114,056)			(114,056)
Retirement Work in Progress (2)		9,307		9,307
Total Reserves for Depreciation	(2,481,959)	(1,867,407)	(315,812)	(4,665,178)
Net Plant in Service	2,770,267	1,082,088	129,908	3,982,263
Other Plant Items				
Construction Work in Progress	35,265	64,959	20,461	120,685
Capitalized Leases			64,525	64,525
Total Other Plant Items	35,265	64,959	84,986	185,210
Plant Related Items and Taxes				
Materials and Supplies	14,214	39,387	10,635	64,236
Fuel Inventories	40,734	113,030	14,783	168,547
Accumulated Deferred ACRS/MACRS	(281,819)	(106,557)	(4,432)	(392,808)
Deferred Investment Tax Credit		(29,110)	(2,829)	(31,939)
SFAS 109 Deferred Tax Assets		5,185	45,311	50,496
Defense Deferred Taxes	(4,879)			(4,879)
Accumulated Deferred Tax - Fuel Oil		16,670		16,670
Environmental Compliance	9,066	15,128		24,194
Total Plant Related Items and Taxes	(222,684)	53,733	63,468	(105,483)
Regulatory Assets and Liabilities				
Flow Through Taxes		7,754		7,754
ECAC and ERAM Balances		(310,026)		(310,026)
Ad Valorem Lien Date Adjustments		3,265		3,265
Balancing Accounts	307,355			307,355
Geysers 15	9,793			9,793
WAPA Power Exchange	137,169			137,169
QF Buyouts	165,710			165,710
Humboldt Bay D&D	3,044			3,044
(Gain) Loss on Reacquired Debt	78,670		4,615	83,285
Debt Discount and Expense			1,727	1,727
SFAS 109 Deferred Taxes	996,690			996,690
Workers' Compensation	26,737			26,737
Long Term Disability	19,235			
PBOP	2,359		87	2,446
Unrecognized PBOP	54,620		2,714	57,334
Unrecognized Pension	11,929		(102)	11,827
Pension			5,439	5,439
Regulatory Liabilities	(23,214)			(23,214)
Abandoned Projects			2,965	2,965
PGE-AMAX Coal contract			4,384	4,384
Total Regulatory Assets and Liabilities	1,790,097	(299,007)	21,829	1,512,919
Total Costs for Eligibility	$ 4,372,945	$ 901,773	$ 300,191	$ 5,574,909

1. Excludes Contractual Obligations and Placeholders
2. Previously included in Construction Work in Progress (CWIP)

Source: Transition Cost Audit Report

ATTACHMENT 2
TRANSITION COST REQUESTS FOR ELIGIBILITY
(Dollars In Thousands)

DESCRIPTION	PG&E Revised Estimate of Eligible Transition Costs at January 1, 1998	Edison Revised Estimate of Eligible Transition Costs at January 1, 1998	SDG&E Revised Estimate of Eligible Transition Costs at January 1, 1998	Total Revised Estimate of Eligible Transition Costs at January 1, 1998
Plant in Service				
Generation	4,912,599	2,832,717	429,532	8,174,848
Generation Related Transmission	265,202	48,728	5,772	319,702
General and Common Plant	80,050	42,929	4,388	127,367
Land and Land Rights	- 42,494	18,777	5,844	67,115
Intangibles	47,373	6,344	168	53,885
Other			16	16
Helms Regulatory Asset	13,845			13,845
Total Plant Investment	5,361,563	2,949,495	445,720	8,756,778
Reserves for Depreciation				
Accumulated Provision	(2,541,738)	(1,876,714)	(352,515)	(4,770,967)
Decommissioning Accrual	(179,374)			(179,374)
Retirement Work in Progress		9,307	27,836	37,143
Total Reserves for Depreciation	(2,721,112)	(1,867,407)	(324,679)	(4,913,198)
Net Plant in Service	2,640,451	1,082,088	121,041	3,843,580
Other Plant Items				
Construction Work in Progress	8,071	63,059	4,993	76,123
Decommissioning Costs	775,542	365,266	70,479	1,211,287
Negative Net Salvage	338,271			338,271
Capitalized Leases			52,292	52,292
Total Other Plant Items	1,121,884	428,325	127,764	1,677,973
Plant Related Items and Taxes				
Materials and Supplies	13,947	39,387	10,535	63,969
Fuel Inventories	28,493	113,030	13,321	154,844
Accumulated Deferred ACRS/MACRS	(273,108)	(105,508)	(4,198)	(382,814)
Deferred Investment Tax Credit		(29,110)	(2,551)	(31,661)
SFAS 109 Deferred Tax Assets		3,785	32,451	36,236
Defense Deferred Taxes	(3,512)			(3,512)
Accumulated Deferred Tax - Fuel Oil		16,670		16,670
Deferred Capitalized Interest	13,383			13,383
TRA 1996 Vacation Day Deferrals	3,315			3,315
Environmental Compliance	11,725	9,644		21,369
Total Plant Related Items and Taxes	(205,757)	47,898	49,658	(108,201)
Regulatory Assets and Liabilities				
Flow Through Taxes		(6,213)		(6,213)
ECAC and ERAM Balances		(220,426)		(220,426)
Ad Valorem Lien Date Adjustments		3,265		3,265
Balancing Accounts	39,123			39,123
WAPA Power Exchange	101,633			101,633
QF Buyouts	40,619	126,000		166,619
Humboldt Bay D&D	1,515			1,515
(Gain) Loss on Reacquired Debt	76,481		4,071	80,552
Debt Discount and Expense			1,555	1,555
SFAS 109 Deferred Taxes	892,267			892,267
Workers' Compensation and LTD	46,634			46,634
PBOP	6,971		(3)	6,968
Unrecognized PBOP	47,645	52,403	2,394	102,442
Unrecognized Pension	9,019		(72)	8,947
Pension	(25,175)		5,682	(20,493)
Abandoned Projects			989	989
PGE-AMAX Coal contract			2,924	2,924
Total Regulatory Assets and Liabilities	1,235,732	(44,971)	17,540	1,208,301
Contractual Obligations				
QF Contracts	28,433,000	29,162,300	2,402,200	59,997,500
Unavoidable Fuel Contracts/ Buyouts		840,500		840,500
Wholesale Power Contracts		2,214,021	726,880	2,940,901
Irrigation District Contracts	939,300			939,300
Geysers Steam Contract	215,200			215,200
Interstate Transition Cost Surcharge	40,500		38,694	79,194
Total Contractual Obligations	29,628,000	32,216,821	3,167,774	65,012,595
Place Holders and Other Costs				
On-Going Cost of Constrained On Plan	621,000			621,000
NOx and HydroRetrofits and Relicensi	258,313			258,313
Hydro - PBR		525,717		525,717
Restructuring Costs	61,877			61,877
1998 Projected Plant Additions	51,851			51,851
Total Place Holders and Other Costs	993,041	525,717		1,518,758
Total Transition Costs Eligibility	$ 35,413,351	$ 34,255,878	$ 3,483,777	73,153,006

Source: Exhibits 114-116

ATTACHMENT 3
Pacific Gas and Electric Company
Net Book Value
(Dollars In Thousands)

DESCRIPTION		Requested Sunk Costs December 31, 1995	Adopted Sunk Costs at December 31, 1995		Rate of Return in Percent
Plant in Service					
Generation		$ 4,799,488	$ 4,798,988	1/	7.13
Generation Related Transmission		265,202	265,202		7.13
General and Common Plant		83,076	83,076		7.13
Land and Land Rights		42,494	42,494		7.13
Intangibles		47,373	47,373		7.13
Helms Regulatory Asset		14,593	14,593		7.13
Total Plant Investment		5,252,226	5,251,726		
Reserves for Depreciation					
Accumulated Provision		(2,367,903)	(2,367,903)		
Decommissioning Accrual		(114,066)	(114,066)		
Total reserves for Depreciation		(2,481,969)	(2,481,969)		
Net Plant in Service		2,770,257	2,769,757		7.13

1. Adjusted for the $500,000 PG&E did not contest with the auditors.

Southern California Edison Company
Net Book Value
(Dollars In Thousands)

DESCRIPTION		Requested Sunk Costs December 31, 1995	Adopted Sunk Costs at December 31, 1995		Rate of Return in Percent
Plant in Service					
Generation		$ 2,832,717	$ 2,832,717		7.22
Generation Related Transmission		48,728	48,728		7.22
General and Common Plant		42,929	42,929		7.22
Land and Land Rights		18,777	18,777		7.22
Intangibles		6,344	3,344		7.22
Total Plant Investment		2,949,495	2,949,495		
Reserves for Depreciation		(1,876,714)	(1,867,407)		
Net Plant in Service		1,072,781	1,082,088		7.22

San Diego Gas and Electric Company
Net Book Value
(Dollars In Thousands)

DESCRIPTION		Requested Sunk Costs December 31, 1995	Adopted Sunk Costs at December 31, 1995		Rate of Return in Percent
Plant in Service					
Generation		$ 429,532	$ 429,532		6.75
Generation Related Transmission		5,772	5,772		6.75
General and Common Plant		4,388	4,388		6.75
Land and Land Rights		5,844	5,844		6.75
Intangibles		168	168		6.75
Other		16	16		
Total Plant Investment		445,720	445,720		
Reserves for Depreciation		(315,812)	(315,812)		
Net Plant in Service		129,908	129,908		6.75

ATTACHMENT 4
TRANSITION COST ELIGIBILITY DETERMINATION
FOR PG&E, EDISON, AND SDG&E

	Description	Eligibility Yes	No	Mixed	Regulatory Treatment	Required Action	Comments	Rate of Return
1	Materials and Supplies (M&S) - All	x			Pre-1998 eligible and Post-1998 are going forward costs.	Physical inventory and market valuation by 12/31/97 or deem book value equal market value at 12/31/97.	This should be filed with appraisal application by 3/2/98.	0
2	Fuel Inventories							
	Oil -PG&E//SDG&E			x	Transition cost Eligibility deferred.	Defer to ISO	None	Carrying cost for 1998 only.
	Oil - Edison			x	Transition cost Eligibility deferred.	File proposal for the treatment of associated revenues by 3/2/98	This should be filed with appraisal application by 3/2/98.	Carrying cost for 1998 only.
	Gas Inventory - Edison	x			Same as M&S	Physical inventory and market valuation by 12/31/97 or book value can be deemed equal to market value at 12/31/97.	This should be filed with appraisal application by 3/2/98.	0
	Coal Inventory - Edison	x			Same as M&S	Same as above.	Possible workshop Ruling to determine transition cost recovery.	0
3	Non-Nuclear Decommissioning Costs Environmental	x			Utilities retain existing liability forecasts.	(1) Rate base offset until 12/31/2001 (2) Amortize 48 months starting 1/1/98 (3) Net present value beginning 2002.	None	0
	Non-Nuclear Decommissioning Costs Non-Environmental	x			Should be captured in divestiture. Until the amortize on current schedule.	None	None	0
4	Construction Work in Progress (CWIP) - 1995			x	Addressed in capital addition proceedings or include as part of market valuation.	None	None	Not Applicable
5	Common and General Plant							
	On-Site	x			Amortize 12/31/95 recorded amounts less offsites.	None	None	Edison - 7.22%, PG&E- 7.13%, SDG&E - 6.75
	Off-Site		x		None	None	Available for other uses or demonstrate not so in a future proceeding.	Not Applicable
6	Emission Credits	x			Credit to TCBA	None	None	Not Applicable
7	Land at Powerplant Sites							
	PG&E	x			To be determined upon final market valuation.	None	None	7.13%
	Edison			x	(1) Functionalize all land, (2) Amortize divested land, (3) Propose treatment for fuel inventory land.	Market value and credit the difference to the TCBA at the date of divestiture.	Include functionalization information with 3/2/98 filing	7.22%
8	Step-up Trans. and Gen. Ties	x			Add to the book value of associated assets.	None	None	Equal to reduced ROR of associated assets.
9	Nuclear Generation Transition Costs							
	ICIP Diablo	x			Incremental Cost Incentive Pricing (ICIP) less market clearing price.	None	None	7.13%
	ICIP SONGS (2&3)	x			Same as Above	None	None	7.35%
	SONGS Upgrade		x		Capacity restricted to adopted benchmark.	None	None	Not Applicable
	Palo Verde Incremental Costs	x			Incremental cost as bills less market clearing price	None	None	7.35%

ATTACHMENT 4

TRANSITION COST ELIGIBILITY DETERMINATION

FOR PG&E, EDISON, AND SDG&E

	Description	Eligibility Yes	No	Mixed	Regulatory Treatment	Required Action	Comments	Rate of Return
10	Fuel and Fuel Transportation							
	PG&E/SDG&E		x		These are going forward costs.	None	None	Not Applicable
	Edison	x			Limited to portion of costs not recovered from market revenues arising from the uneconomic fixed portion of fuel and fuel transportation contracts.	None	Edison shall seek incurred costs in the annual TC proceeding.	0
11	QF Contracts	x			As incurred, contract price compared to market clearing price	None	May be impacted by restructuring/buyouts addressed in a separate proceeding.	0
12	Interutility Contracts	x			Same as for QF	None	None	0
13	Hydroelectric and Geotherm	x			Credit excess revenues beyond the revenue requirement to the TCBA.	None	None	Edison - 7.22%, PG&E - 7.13%
	Hydro-relicensing - Past		x		Should be included in market valuation.	None	None	AFUDC Rate
	Pumped Storage			x	Complete ratemaking determination deferred to A96-07-009	None	None	Reduced ROR
14	Regulatory Assets/Liabilities							
	Workers' Compensation - PG&E		x		Going forward costs.	None	No bright line between pre and post 1998.	Not Applicable
	Long Term Disability - PG&E			x	Pre 1998 is eligible and post 1998 are going forward costs.	None	None	No TCBA Interest
	Post-Retirement Benefits - Edison			x	Same as Above	None	None	No TCBA Interest
	PBOPS/Trans. Benefit Oblig.- All			x	Pre 1998 is eligible and post 1998 are going forward costs.	None	None	No TCBA Interest
	Pension/Trans. Benefit Oblig. - All		x		Regulatory liability should be used to offset TBO regulatory asset and any excess to TCBA.	None	None	No TCBA Interest
	Environmental Compliance		x		None	None	Seek eligibility after costs are incurred.	Not Applicable
	Gain or loss on reacquired debt			x	Pre 1998 is ineligible and post 1998 are eligible.		Seek recovery if/when incurred.	0
15	Deferred Taxes	x			Amortize tax receivables and payables to zero by the end of the transition period.	None		0
16	Balancing Accounts							
	ECAC and ERAM	x			ECAC under/over collections	None	None	0
17	WAPA - PG&E	x			True-up in annual transition cost proceeding	None	None	0
18	QF Buyouts - PG&E	x			Record in the TCBA when approved.	Track in a memo account.	None	0

**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. (U 39 E)	Application No. 96-08-001 (Filed August 1, 1996)
And Consolidated Proceedings	A. 96-08-006 A. 96-08-007
Application of Pacific Gas and Electric Company To Establish the Competition Transition Charge (U 39 E)	Application 96-08-070 (Supplemented October 21,1996)
And Consolidated Proceedings	A. 96-08-071 A. 96-08-072

**CTC PHASE 2
JOINT PROPOSAL AND EXHIBIT
ON TAX RELATED ISSUES
SPONSORED BY ORA, TURN, SCE, SDG&E AND PG&E**

1 Purpose

During Phase 2 of the CTC proceeding, it became apparent that many of the perceived tax disputes raised by parties in their testimony were in fact due to misinterpretations brought about by complex and technical tax jargon used differently by the different parties, rather than arising from any fundamental dispute.

Thus, the participants in this workshop have set out to produce this joint exhibit to highlight areas of agreement, and to draw from each utility's Competition Transition Charge (CTC) filing[1] to provide clear and concise numeric presentations[2] that demonstrate how, and to whom (ratepayers or utilities), tax costs or benefits should flow during the CTC period.

All involved hope that this exhibit will help to avoid time-consuming, expensive, and counterproductive litigation of tax issues in the CTC hearings, where other important issues exist to occupy the parties.

2 Workshop Record

Representatives from Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) met with representatives from the Office of Ratepayer Advocates (ORA) and The Utility Reform Network (TURN). Meetings were held on May 16th, May 28th, June 4th, and June 9th of this year. In addition, phone conferences were held between various parties. While not every representative participated in every session, the participants have all reached consensus on how taxes should be accounted for in the CTC process. That accord is manifested solely in this document.

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[1] A.96-08-070, filed October 21, 1996 for PG&E; A.96-08-071, filed October 21, 1996, as revised February, 1997 for SCE; A.96-08-072, filed October 21, 1996 for SDG&E.
[2] From CTC workpapers; estimated balances as of January 1, 1998; these amounts were audited during the Sunk Cost Audit.

3 Consensus Regarding CTC Accounting for Taxes

Goals

3.1 One of the goals inherent in the Preferred Policy Decision (PPD) and AB 1890 is the full satisfaction of all obligations between ratepayers and investor owned utilities during the CTC period, unless the obligation is specifically excluded, or recovery is statutorily limited.

3.2 To this end, the PPD and AB 1890 accelerate the recovery of remaining above market plant costs and other generation-related costs, including regulatory assets, during the four year CTC transition period, subject to the statutory limitations of a rate freeze and fixed recovery period. There should be an appropriate sharing of benefits and costs between ratepayers and utilities during the CTC period resulting in full satisfaction of non-excluded obligations, and a "clean slate" between ratepayers and utilities thereafter as utility generation competes in the competitive market.

Guidance

3.3 As noted above, the PPD and AB 1890 are the principal sources of authority to determine the industry restructuring goals and limitations that provide a backdrop for sharing tax benefits and tax costs between ratepayers and utilities. Decisions adopted by the Commission during the course of the CTC proceedings will implement the AB 1890 goals and limitations.

3.4 In addition, Internal Revenue Service (IRS) normalization rules contained in the Internal Revenue Code (IRC) should not be disregarded because the severe penalties that would be imposed by the IRS due to a violation would significantly increase ratepayer costs during the transition period. Similarly, other IRC provisions and state tax laws are governing.

3.5 Finally, Financial Accounting Standards Board (FASB) pronouncements also provide guidance. Although the Commission is not bound by these accounting standards, the standards provide valuable direction because they represent the consensus conclusion of a panel of accounting experts reached after thorough and open debate. These conclusions provide a useful framework for recognizing costs and matching costs with benefits. In addition, the same tax-related FASB pronouncements bind non-regulated generators today and will bind the utilities in the same manner after the CTC transition period.

Stipulations

3.6 This agreement addresses property-related taxes (including "tax-on-tax" gross-ups), PG&E's vacation pay deferred tax asset, and SCE's ad valorem lien date tax asset. This agreement does not address or govern any tax or accounting issues arising from other non-property related taxation, such as Post Retirement Benefits other than Pensions (PBOP's) or Pensions.

3.7 The parties agree that CTC Tax Costs (Regulatory Tax Receivables) are fully eligible for recovery during the CTC transition period. Thus, the utilities will have the opportunity to receive full funding for CTC Tax Costs subject only to the statutory limitations (rate freeze and a fixed recovery period) imposed by AB 1890. CTC Tax Costs for property related items are determined as follows[3]:

A. (+ Net Book Value of generation-related plant

- Net Tax Value)

* Applicable Statutory Tax Rate [federal and state]

* Net to Gross Multiplier for Taxes

B. - (Deferred Tax Reserve for normalized property[4],

* Net to Gross Multiplier for Taxes).

3.8 The CTC Revenue Requirement will continue to be adjusted by the amount of revenue requirement associated with a return[5] computed on the Deferred Tax Reserve balance (before gross up) related to taxes on normalized property until the end of the CTC transition period.

3.9 As the CTC Tax Costs related to flow-through property are funded[6] during the CTC transition period, the CTC Revenue Requirement will be adjusted for the amount of revenue requirement associated with a return on the

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[3] This computation is demonstrated in the Appendices attached for each utility, and is incorporated herein by this reference.
[4] This provides ratepayers with a credit for Deferred Taxes previously funded by them.
[5] Return is determined by the appropriate rate of return times the base amount. The appropriate rate of return is either the utility's authorized rate of return, or the reduced rate of return provided for in AB 1890 when a utility accelerates recovery of uneconomic costs, as applicable.
[6] The Minkin Proposed Decision provides for ordering of recovery based on the rate-of-return earned by the various assets, while the Conlon Proposed Decision requires level amortization over 48 months. In either case, the Deferred Tax Reserve related to flow-through taxes will increase or decrease as a function of the pattern of amortization of the regulatory asset or liability and the level of current taxes paid to taxing authorities.

funded Deferred Tax Reserve balance (related to taxes on flow-through property) until the end of the CTC transition period[7].

3.10 All property-related regulatory tax receivables and/or payables will be amortized to zero by the end of the CTC transition period. This will settle all property-related tax benefits or obligations between ratepayers and utilities. No further sharing of benefits or obligations will occur beyond the end of the CTC transition period, except as provided for in the decisions relating to the Diablo Canyon, Palo Verde, and San Onofre nuclear plants.

3.11 PG&E ratepayers will continue to receive a credit against the CTC Revenue Requirement for the amount of revenue requirement associated with a return on the Unamortized Investment Tax Credit (ITC) balance, as permitted by IRC Section 46(f)(1), during the CTC period.

3.12 SCE and SDG&E ratepayers will continue to receive a credit against the CTC Revenue Requirement for the amount of the revenue requirement associated with the amortization of ITC, as permitted by IRC Section 46(f)(2), during the CTC period.

3.13 SCE's Regulatory Tax Asset related to the Ad Valorem Lien Date Adjustment will be treated as follows:

- During the first three years of the CTC period, or until the property generating the ad valorem lien date adjustment is sold, whichever comes first, the ad valorem lien date regulatory receivable will be

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[7] Traditionally, the Regulatory Asset and the Deferred Tax Liability have been of equal but opposite amounts. During the CTC period, this relationship will be decoupled as the Regulatory Receivable will be recovered over the CTC period, but the Deferred Tax Liability will unwind naturally. This will have the effect of funding the deferred tax over the CTC period. This funded amount (Regulatory Receivable - Deferred Tax Liability) will earn or pay a return which will be included in the CTC Revenue Requirement.

adjusted annually using the method contained in SCE's CTC workpapers. That is, tax benefits for ad valorem taxes will continue to be flowed through to ratepayers in advance of payment of the tax. The cumulative amount of this benefit, which is reflected in the tax regulatory asset, will change annually based upon the property tax due and the benefits provided to ratepayers.

- If a plant is sold or divested, the ad valorem lien date regulatory tax asset related to that plant will be included in the gain on sale computation and will be fully recoverable from ratepayers at that time.
- To the extent the ad valorem lien date regulatory tax asset has not been recovered on or before January 1, 2001, it will be recoverable in full from ratepayers in that year or in the last year of the CTC period if that occurs earlier.

3.14 PG&E's Vacation Pay Deferred Tax Asset will not be amortized during the CTC transition period. However, PG&E will continue to increase the CTC Revenue Requirement for the amount of the revenue requirement associated with a return on the Vacation Pay Deferred Tax Asset, as adjusted for the impact of asset sales or market valuations.

3.15 This agreement formally and with finality concludes and resolves all property-related tax issues raised by and between the workshop participants[8]. The participants ask the Commission to give this document favorable weight in determining the outcome of these issues.

4 Accounting Presentation from Each Utility

Attached are summaries of the plant and tax amounts, as of January 1, 1998, that will be recovered by each utility or credited to ratepayers, subject to Commission approval. Note that these are estimated amounts from each utility's

[8] The workshop participants included all who raised property-related tax issues during the CTC proceeding to date. In addition, ALJ Minkin announced the start of the workshop, and extended an invitation to all interested parties to attend.

CTC filing; actual amounts as of January 1, 1998, will be based on the books of account of each utility and provisions of Commission decisions resolving disputed issues related to the CTC treatment of underlying property, and will likely be different from the forecast amounts. Also attached is an appendix containing definitions agreed upon by the participants.

5 Conclusion

The participants believe that the goals of the PPD and AB 1890 are met through the tax accounting detailed above. The accounting fairly shares benefits and costs during the CTC transition period, concludes obligations between ratepayers and utilities at the end of the CTC period, and at all times accommodates requirements imposed by taxing authorities and others.

CTC Tax Workshop
Pacific Gas & Electric Company
Non-Nuclear Generation Regulatory Receivable for Taxes - Property Related

Total Non-Nuclear		
Net Book Value at January 1, 1998		$ 2,629,525,000
Net Book Value Tax Gross up:		
Net Book Value	2,629,525,000	
Remaining State Tax Basis *	(1,064,447,000)	
Net Excess Includable in Taxable Income	1,565,078,000	
State Tax Rate	8.840%	
State Tax Differences Before Gross Up	138,352,895	
Net to Gross Multiplier for Taxes	1.68765	
Deferred Tax Liability (due from ratepayers)		233,491,263
Net Book Value Tax Gross up:		
Net Book Value	2,629,525,000	
Remaining Federal Tax Basis	(1,064,447,000)	
State Tax Differences Before Gross Up	(138,352,895)	
Net Excess Includable in Taxable Income	1,426,725,105	
Federal Tax Rate	35.000%	
Net to Gross Multiplier for Taxes	1.68765	
Deferred Tax Liability (due from ratepayers)		842,734,418
Normalized Deferred Tax Reserve:		
ACRS/MACRS Deferred Tax **	273,108,000	
Net to Gross Multiplier for Taxes	1.68765	
Total (credit to ratepayers)		(460,910,716)
Deferred ITC:		
Unamortized ITC		See page 6
Return on Unamortized ITC balance (per IRC 46(f)(1))		See page 6
Net to Gross Multiplier for Taxes		See page 6
Total (credit to ratepayers)		(28,210,064)
CTC Revenue Requirement before Valuation		3,216,629,901
Less Valuation ***		0
Net CTC Revenue Requirement		3,216,629,901
Net Book Value		(2,629,525,000)
Net CTC Revenue Requirement for Taxes		587,104,901

* PG&E used a combined tax rate in its forecast to estimate the state tax liability.

** Amount includes ARAM. If the plant was sold or valued at an amount other than zero, a portion of this would be retained by PG&E in accordance with Internal Revenue Code normalization rules.

*** For purposes of this computation, pending actual valuation or sale, the valuation has been assumed to be zero.

CTC Tax Workshop
Pacific Gas & Electric Company
Non-Nuclear Generation Regulatory Receivable for Taxes - Property Related

Fossil		
Net Book Value at January 1, 1998		$ 827,137,000
Net Book Value Tax Gross up:		
Net Book Value	827,137,000	
Remaining State Tax Basis *	(496,447,000)	
Net Excess Includable in Taxable Income	330,690,000	
State Tax Rate	8.840%	
State Tax Differences Before Gross Up	29,232,996	
Net to Gross Multiplier for Taxes	1.68765	
Deferred Tax Liability (due from ratepayers)		49,335,066
Net Book Value Tax Gross up:		
Net Book Value	827,137,000	
Remaining Federal Tax Basis	(496,447,000)	
State Tax Differences Before Gross Up	(29,232,996)	
Net Excess Includable in Taxable Income	301,457,004	
Federal Tax Rate	35.000%	
Net to Gross Multiplier for Taxes	1.68765	
Deferred Tax Liability (due from ratepayers)		178,063,869
Normalized Deferred Tax Reserve:		
ACRS/MACRS Deferred Tax **	29,110,000	
Net to Gross Multiplier for Taxes	1.68765	
Total (credit to ratepayers)		(49,127,492)
Deferred ITC:		
Unamortized ITC		See page 6
Return on Unamortized ITC balance (per IRC 46(f)(1))		See page 6
Net to Gross Multiplier for Taxes		See page 6
Total (credit to ratepayers)		(10,299,893)
CTC Revenue Requirement before Valuation		995,108,550
Less Valuation ***		0
Net CTC Revenue Requirement		995,108,550
Net Book Value		(827,137,000)
Net CTC Revenue Requirement for Taxes		167,971,550

* PG&E used a combined tax rate in its forecast to estimate the state tax liability.

** Amount includes ARAM. If the plant was sold or valued at an amount other than zero, a portion of this would be retained by PG&E in accordance with Internal Revenue Code normalization rules.

*** For purposes of this computation, pending actual valuation or sale, the valuation has been assumed to be zero.

CTC Tax Workshop
Pacific Gas & Electric Company
Non-Nuclear Generation Regulatory Receivable for Taxes - Property Related

Geothermal		
Net Book Value at January 1, 1998		$ 341,890,000
Net Book Value Tax Gross up:		
Net Book Value	341,890,000	
Remaining State Tax Basis *	(107,765,000)	
Net Excess Includable in Taxable Income	234,125,000	
State Tax Rate	8.840%	
State Tax Differences Before Gross Up	20,696,650	
Net to Gross Multiplier for Taxes	1.68765	
Deferred Tax Liability (due from ratepayers)		34,928,701
Net Book Value Tax Gross up:		
Net Book Value	341,890,000	
Remaining Federal Tax Basis	(107,765,000)	
State Tax Differences Before Gross Up	(20,696,650)	
Net Excess Includable in Taxable Income	213,428,350	
Federal Tax Rate	35.000%	
Net to Gross Multiplier for Taxes	1.68765	
Deferred Tax Liability (due from ratepayers)		126,067,324
Normalized Deferred Tax Reserve:		
ACRS/MACRS Deferred Tax **	43,275,000	
Net to Gross Multiplier for Taxes	1.68765	
Total (credit to ratepayers)		(73,033,054)
Deferred ITC:		
Unamortized ITC		See page 6
Return on Unamortized ITC balance (per IRC 46(f)(1))		See page 6
Net to Gross Multiplier for Taxes		See page 6
Total (credit to ratepayers)		(4,610,790)
CTC Revenue Requirement before Valuation		425,242,181
Less Valuation ***		0
Net CTC Revenue Requirement		425,242,181
Net Book Value		(341,890,000)
Net CTC Revenue Requirement for Taxes		83,352,181

* PG&E used a combined tax rate in its forecast to estimate the state tax liability.

** Amount includes ARAM. If the plant was sold or valued at an amount other than zero, a portion of this would be retained by PG&E in accordance with Internal Revenue Code normalization rules.

*** For purposes of this computation, pending actual valuation or sale, the valuation has been assumed to be zero.

CTC Tax Workshop
Pacific Gas & Electric Company
Non-Nuclear Generation Regulatory Receivable for Taxes - Property Related

Hydro		
Net Book Value at January 1, 1998		$ 822,270,000
Net Book Value Tax Gross up:		
Net Book Value	822,270,000	
Remaining State Tax Basis *	(407,736,000)	
Net Excess Includable in Taxable Income	414,534,000	
State Tax Rate	8.840%	
State Tax Differences Before Gross Up	36,644,806	
Net to Gross Multiplier for Taxes	1.68765	
Deferred Tax Liability (due from ratepayers)		61,843,607
Net Book Value Tax Gross up:		
Net Book Value	822,270,000	
Remaining Federal Tax Basis	(407,736,000)	
State Tax Differences Before Gross Up	(36,644,806)	
Net Excess Includable in Taxable Income	377,889,194	
Federal Tax Rate	35.000%	
Net to Gross Multiplier for Taxes	1.68765	
Deferred Tax Liability (due from ratepayers)		223,210,644
Normalized Deferred Tax Reserve:		
ACRS/MACRS Deferred Tax **	64,233,000	
Net to Gross Multiplier for Taxes	1.68765	
Total (credit to ratepayers)		(108,402,822)
Deferred ITC:		
Unamortized ITC		See page 6
Return on Unamortized ITC balance (per IRC 46(f)(1))		See page 6
Net to Gross Multiplier for Taxes		See page 6
Total (credit to ratepayers)		(9,046,845)
CTC Revenue Requirement before Valuation		989,874,784
Less Valuation ***		0
Net CTC Revenue Requirement		989,874,784
Net Book Value		(822,270,000)
Net CTC Revenue Requirement for Taxes		167,604,784

* PG&E used a combined tax rate in its forecast to estimate the state tax liability. For Hydro, a rate of 9.3% was used in the filing. Here, the rate has been corrected to 8.84%, lowering tax costs.

** Amount includes ARAM. If the plant was sold or valued at an amount other than zero, a portion of this would be retained by PG&E in accordance with Internal Revenue Code normalization rules.

*** For purposes of this computation, pending actual valuation or sale, the valuation has been assumed to be zero.

CTC Tax Workshop
Pacific Gas & Electric Company
Non-Nuclear Generation Regulatory Receivable for Taxes - Property Related

Helms		
Net Book Value at January 1, 1998		$ 638,228,000
Net Book Value Tax Gross up:		
Net Book Value	638,228,000	
Remaining State Tax Basis *	(52,499,000)	
Net Excess Includable in Taxable Income	585,729,000	
State Tax Rate	8.840%	
State Tax Differences Before Gross Up	51,778,444	
Net to Gross Multiplier for Taxes	1.68765	
Deferred Tax Liability (due from ratepayers)		87,383,891
Net Book Value Tax Gross up:		
Net Book Value	638,228,000	
Remaining Federal Tax Basis	(52,499,000)	
State Tax Differences Before Gross Up	(51,778,444)	
Net Excess Includable in Taxable Income	533,950,556	
Federal Tax Rate	35.000%	
Net to Gross Multiplier for Taxes	1.68765	
Deferred Tax Liability (due from ratepayers)		315,392,580
Normalized Deferred Tax Reserve:		
ACRS/MACRS Deferred Tax **	136,490,000	
Net to Gross Multiplier for Taxes	1.68765	
Total (credit to ratepayers)		(230,347,349)
Deferred ITC:		
Unamortized ITC		See page 6
Return on Unamortized ITC balance (per IRC 46(f)(1))		See page 6
Net to Gross Multiplier for Taxes		See page 6
Total (credit to ratepayers)		(4,252,736)
CTC Revenue Requirement before Valuation		806,404,386
Less Valuation ***		0
Net CTC Revenue Requirement		806,404,386
Net Book Value		(638,228,000)
Net CTC Revenue Requirement for Taxes		168,176,386

* PG&E used a combined tax rate in its forecast to estimate the state tax liability.

** Amount includes ARAM. If the plant was sold or valued at an amount other than zero, a portion of this would be retained by PG&E in accordance with Internal Revenue Code normalization rules.

*** For purposes of this computation, pending actual valuation or sale, the valuation has been assumed to be zero.

CTC Tax Workshop
Pacific Gas & Electric Company
Non-Nuclear Generation Regulatory Receivable for Taxes - Property Related

Weighted Average ITC

From CTC WP	1998	1999	2000	2001	Total
Fossil	$ 23,421,000	22,272,000	21,122,000	19,973,000	
Geothermal	10,486,000	9,971,000	9,455,000	8,939,000	
Hydro	20,567,000	19,560,000	18,553,000	17,548,000	
Helms	9,365,000	9,094,000	8,823,000	8,552,000	
	63,839,000	60,897,000	57,953,000	55,012,000	
46(f)(1) Calculation					
Fossil	$ 23,421,000	$ 22,272,000	$ 21,122,000	$ 19,973,000	
Rate of Return *	9.45%	9.45%	9.45%	9.45%	
Return Net-to-Gross Multiplier **	1.25586	1.25586	1.25586	1.25586	
Credit to Return ***	2,779,575	2,643,214	2,506,733	2,370,371	10,299,893
Geothermal	$ 10,486,000	$ 9,971,000	$ 9,455,000	$ 8,939,000	
Rate of Return	9.45%	9.45%	9.45%	9.45%	
Return Net-to-Gross Multiplier	1.25586	1.25586	1.25586	1.25586	
Credit to Return	1,244,466	1,183,346	1,122,108	1,060,870	4,610,790
Hydro	$ 20,567,000	$ 19,560,000	$ 18,553,000	$ 17,548,000	
Rate of Return	9.45%	9.45%	9.45%	9.45%	
Return Net-to-Gross Multiplier	1.25586	1.25586	1.25586	1.25586	
Credit to Return	2,440,866	2,321,357	2,201,847	2,082,575	9,046,645
Helms	$ 9,365,000	$ 9,094,000	$ 8,823,000	$ 8,552,000	
Rate of Return	9.45%	9.45%	9.45%	9.45%	
Return Net-to-Gross Multiplier	1.25586	1.25586	1.25586	1.25586	
Credit to Return	1,111,427	1,079,265	1,047,103	1,014,941	4,252,736
				Total	28,210,064

* Estimated Rate of Return; the actual rate used during the CTC period will be different, and normally is stated with the equity grossup included.

** Only the equity component in the rate of return requires a gross-up. Here, current statutory tax rates are used with an assumed debt/equity ratio of 50% to develop this estimate; the actual gross up rate will vary.

*** For purposes of this exhibit, return is not included, and only this ITC adjustment to return is shown.

CTC Tax Workshop
Southern California Edison
Non-Nuclear Generation Regulatory Receivable for Taxes - Summary

$ IN THOUSANDS

Regulatory Tax Receivable - Non-nuclear Generation	
Property Related	$9,003
Ad Valorem Lien Date	3,738
Investment Tax Credit	(14,775)
Total	($2,034)
Deferred Investment Tax Credit	($25,096)

CTC Tax Workshop
Southern California Edison
Non-Nuclear Generation Regulatory Receivable for Taxes - Property Related

Net Book Value at January 1, 1998		1,104,487,000
Net Book Value Tax Gross up:		
Net Book Value	1,104,487,000	
Remaining State Tax Basis	(921,569,000)	
Net	182,918,000	
Apportioned State Tax Rate	8.53980%	
Net to Gross Multiplier for Taxes	1.68211	
Total		26,275,957
Net Book Value	1,104,487,000	
Remaining Federal Tax Basis	(747,602,000)	
State Tax Differences before Gross Up *	(15,620,831)	
Net	341,264,169	
Federal Tax Rate	35%	
Net to Gross Multiplier for Taxes	1.68211	
Total		200,915,355
Normalized Deferred Tax Reserve:		
ACRS / MACRS Deferred Tax **	134,592,000	
Unicap Deferred Tax	(4,881,000)	
Normalized Taxes	129,711,000	
Net to Gross Multiplier for Taxes	1.68211	
Total		(218,188,170)
CTC Revenue Requirement before Valuation		1,113,490,142
Less Valuation ***		0
Net CTC Revenue Requirement		1,113,490,142
Net Book Value		(1,104,487,000)
Net CTC Revenue Requirement for Taxes		9,003,142

This schedule does not include amounts related to Hydro.

* Amount is computed as $182,918,000 * 8.5398%

** Amount includes ARAM. If the plant was sold or valued at an amount other than zero, a portion of this would not be available to ratepayers in compliance with the Internal Revenue Code normalization rules.

*** For purposes of this computation, pending actual valuation or sale, the valuation has been assumed to be zero.

CTC Tax Workshop
Southern California Edison
Non-Nuclear Generation Regulatory Receivable for Taxes - Ad Valorem Lien Date

Timing Difference - Ad Valorem Taxes		
Lien Date Adjustment - Non-Nuclear	5,480,000	
Apportioned Tax Rate	40.55087%	
Net to Gross Multiplier for Taxes	1.68211	
Total		3,737,964
Normalized Deferred Tax Reserve:		
Normalized Taxes	0	
Net to Gross Multiplier for Taxes	1.68211	
Total		0
CTC Revenue Requirement		3,737,964

This schedule does not include amounts related to Hydro.

CTC Tax Workshop
Southern California Edison
Non-Nuclear Generation Regulatory Receivable for Taxes - Investment Tax Credit

Investment Tax Credit		
Deferred ITC - Non-Nuclear at 1/1/98	(25,096,000)	
Federal Tax Rate	35%	
Net to Gross Multiplier for Taxes	1.68211	
Total		(14,774,981)
Normalized Deferred Tax Reserve:		
Normalized Taxes	0	
Net to Gross Multiplier for Taxes	1.68211	
Total		0
CTC Revenue Requirement *		(14,774,981)

This schedule does not include amounts related to Hydro.

* Only the gross-up related to ITC is included with the Regulatory Assets for Taxes; the Deferred ITC itself was separately listed. If the plant is sold or is valued at an amount other than zero, a portion of this would not be available to ratepayers in compliance with the Internal Revenue Code normalization rules.

Application No: 96-08-071
Exhibit No: SCE-11A
(Update to SCE-11)
Witness: D. J. Klun

SOUTHERN CALIFORNIA
EDISON

An *EDISON INTERNATIONAL* Company

(U 338-E)

Update To Transition Costs For Regulatory Assets, Obligations, And Balancing Accounts

Before the
Public Utilities Commission of the State of California

Rosemead, California
February 1997

REGULATORY ASSETS-NUCLEAR GENERATION
DECEMBER 31, 1997 THROUGH 2001

DESCRIPTION	12/31/95 Nuclear Generation	1996 Activity	12/31/96 Balance	Tax Rate Change	Adj.12/31/96 Balance	1997 Activity	1/1/98 Balance	1998 Activity	12/31/98 Balance
UNREALIZED GAIN/LOSS ACE/EXEL	0.00	0.00	0.00	7.40	0.00	0.00	0.00	0.00	0.00
UNREALIZED GAIN/LOSS ACE/EXEL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ENVEST STARTUP COSTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ETC-FERC-COOLWATER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ACE LIMITED INSURANCE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AD VALOREM LIEN DATE-GAS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AD VALOREM LIEN DATE-WATER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ACCRUED VACATION	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AD VALOREM LIEN DATE-ELECTRIC	17,877,264.29	(3,066,800.57)	14,810,463.72	(299,932.60)	14,510,531.12	(1,693,679.72)	12,816,851.40	(2,667,733.15)	10,149,118.25
UNREALIZED HOLDING GAINS/LOSSES	(11,708,968.01)	(62,695,340.43)	(74,404,308.44)	2,103,267.85	(72,301,040.59)	0.00	(72,301,040.59)	0.00	(72,301,040.59)
INVESTMENT IN EXCESS OF COST	11,708,968.01	62,695,340.43	74,404,308.44	(2,103,267.85)	72,301,040.59	0.00	72,301,040.59	0.00	72,301,040.59
INSURANCE RESERVE/CASUALTY LOSSES	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CIAC - DEFERRED REVENUE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DECOMM CONTRIBUTION - NON-QUAL	(74,959,367.00)	2,470,505.95	(72,488,861.05)	1,467,961.02	(71,020,900.03)	(2,976,941.37)	(73,997,841.40)	(2,976,991.37)	(76,974,832.77)
DECOMMISSIONING TRUST EARN-NG BOOK	4,690,421.18	3,753,396.30	8,443,817.48	(170,993.52)	8,272,823.96	2,402,888.51	10,675,712.47	2,606,676.34	13,282,388.81
PBOP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HAZARDOUS WASTE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UNCOLLECTIBLE ACCTS - OAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DOE DECONTAMINATION	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DECOMMISSIONING TRUST EARN-NG TAX	(3,033,647.68)	(9,144,608.37)	(12,178,256.05)	101,226.46	(12,077,029.59)	(5,925,616.17)	(18,002,644.76)	(6,428,163.79)	(24,430,808.55)
UNCOLLECTIBLE ACCOUNTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PROPERTY RELATED ITEMS	894,906,000.00	(88,711,000.00)	806,195,000.00	(24,298,000.00)	781,897,000.00	(217,399,000.00)	564,498,000.00	(251,889,000.00)	312,609,000.00
DEFERRED ITC ITEMS	(107,768,893.00)	9,204,308.00	(98,564,585.00)	818,275.00	(97,746,310.00)	15,616,878.00	(82,129,432.00)	20,533,255.00	(61,596,177.00)
	731,711,727.19	(85,494,098.07)	646,217,628.50	(22,309,463.94)	623,907,165.46	(209,976,612.78)	413,931,545.71	(240,722,964.97)	172,938,098.74

Account 182.379 ARAM is included in the normal deferred taxes.

RGAS1.WK4

REGULATORY ASSETS - NON-NUCLEAR GENERATION
DECEMBER 31, 1997 THROUGH 2001

ACCOUNT NUMBER	DESCRIPTION	12/31/95 Non-Nuclear Gen	1996 Activity	12/31/96 Balance	Tax Rate Change	Adj 12/31/96 Balance	1997 Activity	1/1/98 Balance	1998 Activity	12/31/98 Balance
182.226	UNREALIZED GAIN/LOSS ACE/EXEL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182.226	UNREALIZED GAIN/LOSS ACE/EXEL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182.306	ENVEST STARTUP COSTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182.307	ETC-FERC-COOLWATER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182.310	ACE LIMITED INSURANCE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182.311	AD VALOREM LIEN DATE-GAS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182.312	AD VALOREM LIEN DATE-WATER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182.313	ACCRUED VACATION	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182.314	AD VALOREM LIEN DATE-ELECTRIC	3,266,220.14	616,841.16	3,882,061.30	(78,614.61)	3,803,446.69	(65,482.58)	3,737,964.11	22,509.64	3,760,473.75
182.316	UNREALIZED HOLDING GAINS/LOSSES	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182.317	INVESTMENT IN EXCESS OF COST	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182.319	INSURANCE RESERVE/CASUALTY LOSSES	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182.321	CIAC - DEFERRED REVENUE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182.322	DECOMM NET EARN-NON-QUAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182.326	DECOMMISSIONING TRUST-NQ BOOK	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182.331	PBOP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182.332	HAZARDOUS WASTE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182.343	UNCOLLECTIBLE ACCTS - OAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182.369	DOE DECONTAMINATION	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182.365	DECOMMISSIONING TRUST-NQ EXPENSE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182.366	UNCOLLECTIBLE ACCOUNTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	PROPERTY RELATED ITEMS	25,036,000.00	(6,405,000.00)	18,631,000.00	(1,547,000.00)	17,084,000.00	(8,081,000.00)	9,003,000.00	(42,092,000.00)	(33,089,000.00)
	DEFERRED ITC ITEMS	(17,281,826.00)	1,194,470.00	(16,087,356.00)	133,719.00	(15,953,636.00)	1,178,655.00	(14,774,981.00)	3,695,511.00	(11,079,470.00)
		11,019,396.14	(4,593,688.84)	6,425,705.30	(1,491,895.61)	4,933,810.69	(6,967,827.58)	(2,034,016.89)	(38,373,979.36)	(40,407,996.25)

Account 182.379 ARAM is included in the normal deferred taxes.

RGAS1.WK4

FILE: TX_RTFUT.WK4

Tax Rates

	1997 Statutory Rate	1995 ORC Apportionment Factor	Ratio of State Income To California		Ratemaking Tax Rates
California	8.8400%	93.0762%	100.0000%	8.2279%	8.2279%
Arizona (Note)	8.2569%	2.9878%	95.2655%	0.2350%	0.2350%
New Mexico	7.6000%	1.1776%	85.8768%	0.0769%	0.0769%
Total States				8.5398%	
Federal Statutory Rate				35.0000%	35.0000%
Federal Benefit of State Taxes				2.98893%	-2.98893%
Total					40.55087%

(Note) Rate for Arizona to give effect to deduction of Arizona Income Tax

(A)	Statutory Rate	9.0000%
(B)	1 Plus Statutory Rate	109.0000%
	Arizona Effective Rate = (A) ÷ (B)	8.2569%

FILE: TX_RTFUT.WK4

Gross-Up Rate

State Composite		
Federal Statutory Rate	8.5398% 35.0000%	8.5398%
Federal Benefit of State Taxes	2.98893%	-2.98893%
Federal Statutory Rate		35.00000%
Total		40.55087%
Gross-Up Rate 1 ÷ (1 - 40.55087%) =		1.682110

CTC TAX WORKSHOP
SAN DIEGO GAS & ELECTRIC
NON-NUCLEAR GENERATION REGULATORY RECEIVABLE FOR TAXES - PROPERTY RELATED

Total Non-Nuclear		
Net Book Value at January 1, 1998		151,866,000
Net Book Value Tax Gross up:		
Net Book Value	151,866,000	
Remaining State Tax Basis	(101,234,086)	
Net	50,631,914	
Apportioned State Tax Rate	8.84%	
Net to Gross Multiplier for Taxes	1.68765	
Total		7,553,686
Net Book Value	151,866,000	
Remaining Federal Tax Basis	(90,964,825)	
State Tax Differences before Gross Up (1)	(4,475,861)	
Net	56,425,314	
Federal Tax Rate	35%	
Net to Gross Multiplier for Taxes	1.68765	
Total		33,329,159
Normalized Deferred Tax Reserve:		
ACRS/MACRS Deferred Tax (2)	5,265,000	
Unicap Deferred Tax	(1,067,000)	
Normalized Taxes	4,198,000	
Net to Gross Multiplier for Taxes	1.68765	
Total		(7,084,754)
Deferred ITC:		
Unamortized ITC (3)	2,550,592	
Net to Gross Multiplier for Taxes	1.68765	
Total		(4,304,506)
CTC Revenue Requirement before Valuation		181,359,585
Less Valuation (4)		0
Net CTC Revenue Requirement		181,359,585
Net Book Value		(151,866,000)
Net CTC Revenue Requirement for Taxes		29,493,585

(1) Amount is computed as $50,631,914 * 9.3%

(2) Amount includes ARAM. If the plant was sold or valued at an amount other than zero, a portion of this would not be available to ratepayers in compliance with the Internal Revenue Code normalization rules.

(3) If the plant is sold or is valued at an amount other than zero, a portion of Deferred ITC would not be available to ratepayers in compliance with the Internal Revenue Code normalization rules.

(4) For purposes of this computation, pending actual valuation or sale, the valuation has been assumed to be zero.

CTC TAX WORKSHOP
APPENDIX TO
JOINT PROPOSAL AND EXHIBIT

1 Definitions

The participants have agreed upon the following definitions:

1.1 DEFERRED TAX LIABILITY (DTL)

Taxes owed by the utilities to taxing authorities. The liability is based on the difference between book and tax basis, after accounting for accumulated book depreciation and accumulated tax depreciation to date. The difference times the applicable tax rate establishes the nominal amount of the liability. The liability generally will not come due immediately, but will be paid over time.

1.2 DEFERRED TAX ASSET (DTA)

Income taxes due from taxing authorities to the utilities. A DTA will usually come about because book treatment is more favorable than the corresponding tax treatment. For example, PG&E's treatment of vacation pay gives rise to a DTA because PG&E funds the taxes due. When a DTA is created, the utilities have paid more in tax today, but will receive future tax deductions that yield a tax benefit later.

1.3 FLOW-THROUGH TAX ACCOUNTING

Under this method of ratemaking, tax expense is included in the test year revenue requirement based on actual cash taxes paid to taxing authorities. Thus, the benefit of accelerated tax depreciation is passed through to ratepayers in the early years of an asset's life, but is repaid in the form of higher rates in the later years of the asset's life. The Commission has adopted flow-through tax accounting for pre-1981 additions to plant, post-1980 differences between book and tax basis, and state taxes.

1.4 NORMALIZED TAX ACCOUNTING[1]

This method of ratemaking sets rates based on tax expense computed as if book depreciation (which is not accelerated) were deductible on tax returns. In effect, ratepayers reimburse utilities for total tax expense, including current and deferred taxes. This increases ratemaking tax expense initially, and gives utilities cash for deferred tax expense in excess of amounts actually paid to tax authorities in the early years of the asset's life. However, in the later years of an asset's life, ratepayers benefit from lower rates because the total tax expense is lower, and the Deferred Tax Reserve is used to pay current taxes due to taxing authorities in excess of the total tax expense recovered in rates.

1.5 DEFERRED TAX RESERVE

For assets subject to normalized tax accounting, ratepayers will pay for a level of tax expense in rates, in the early years of the asset's life, that is higher than the tax expense paid by the utilities to taxing authorities. This extra amount funds a Deferred Tax Reserve that reverses in later years to pay tax expense to taxing authorities that is higher than that collected in

[1] Applies predominantly to life and method timing differences on plant placed-in-service after 1980.

rates. During the existence of the reserve, it is used to lower rate base, thus providing a benefit to ratepayers by lowering the return component of rates.

1.6 REGULATORY ASSET OR RECEIVABLE

Amounts owed by the ratepayers to utilities. As defined above, a DTL can be computed for any asset based on the relative amounts of book and tax depreciation taken to date. If the asset was subject to flow-through tax accounting, the utilities have a regulatory receivable that recognizes that ratepayers have benefited from lower rates in the early years of the asset's life, with the expectation of paying higher rates in the future in order to pay the DTL. If the asset was subject to normalization tax accounting, the ratepayers have funded the DTL; thus, there will not generally be a regulatory asset in conjunction with normalized assets.

1.7 REGULATORY LIABILITY OR PAYABLE

Amounts owed by the utilities to ratepayers.

2 <u>The Ratemaking Tax Algorithm</u>

This complex issue of fixed asset taxation can be clarified through understanding the following principles:

2.1 Depreciation is beneficial to ratepayers and utilities because it is deductible, and therefore lowers tax expense.

2.2 Book and tax depreciation at the end of life for any given asset will be exactly the same.

2.3 If book and tax depreciation during the life of the asset is the same, taxes do not present an issue because there is conformity between the book and tax expense levels. The ratemaking revenue requirement would be based solely on recovery of the plant investment.

2.4 However, tax depreciation is generally accelerated compared to book depreciation, creating a "gap" between book and tax during the life of the asset.

2.5 As this gap is closed (via reimbursement in rates for book deprecation that is treated as income for tax purposes because accelerated tax depreciation has already reduced taxable income in prior periods), taxes will be due to the taxing authorities.

2.6 If ratepayers reimbursed utilities for tax expense based on actual tax depreciation ("flow-through"), then ratepayers will benefit from lower rates as the gap builds up, but must pay higher rates to close the gap in the later years of the asset's life, because utilities will pay taxes on the gap.

2.7 If ratepayers reimbursed utilities for tax expense as if book depreciation were deductible, then they have funded ("normalized") the taxes due on the gap. Ratepayer funding will be used on behalf of ratepayers to pay taxes due to taxing authorities as the gap is closed.

3 <u>Complications Raised by the CTC</u>

3.1 As noted above, either the flow-through or normalized methods of tax accounting will generally yield the same revenue requirement over the life of the asset. (The normalization method will produce a somewhat lower revenue requirement in nominal dollars, since the Deferred Tax Reserve lowers rate base, and thus the return component of rates).

3.2 Under CTC, the regulated status of the assets will come to a close at the end of the transition period; this is generally before the assets will have fully depreciated. This book depreciation is now being accelerated; thus there is a need to fund taxes on the "gap" under CTC that would normally unwind in due course under cost-of-service regulation, but which will now be accelerated.

3.3 In effect, the Preferred Policy Decision and AB 1890 require utilities to credit ratepayers for the reversal of the Deferred Tax Reserve in computing the CTC revenue requirement. In addition, ratepayers must now make a "catch up" payment over the transition period to repay the benefits previously received by ratepayers on the flow-through assets and to fund the Deferred Tax Reserve. Once funded, the Deferred Tax Reserve will be used to pay taxes due to taxing authorities.

(END OF ATTACHMENT 5)

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(END OF APPENDIX A)

COMMISSIONER JESSIE J. KNIGHT, JR., CONCURRING:

The estimated eligible transition costs are large, but I am confident that they been reduced to the greatest practical extent under the law. More importantly, this reiterates the key policy principle that going forward costs must be recovered from the market. I concur with this policy principle. Once a generation plant has been given its market valuation, that plant must make economic sense to operate on a going-forward basis. The utility will have to make the business decision as to whether the plant should continue to operate. It is imperative that utilities not have competitive advantage through transition cost subsidization of assets that are uneconomic on a going forward basis. If a plant cannot compete on a going-forward basis it has no place in a competitive market and no place in California's future.

I take this opportunity to express my commitment that the Commission will thoroughly review amounts posted to the transition cost balancing account in this proceeding, and particularly the monthly posting to the plant-specific accounts, to ensure that transition costs are minimized and to prevent any competitive advantage to utility plants that could arise by transition cost subsidization of plant operating costs.

This decision estimates the total costs eligible for transition costs recovery. We know that the actual amount of transition costs will be less than this because this estimation will be offset by the market valuation of the plants and other assets. What we can say with certainty is that these are not new costs and that these costs would have been recovered from ratepayers under the traditional regulatory framework. In fact, absent restructuring these costs would have been higher because they would have been subjected to the higher carrying costs reflected by the utilities cost of capital. Furthermore, we can only begin to ponder what the next generation of uneconomic investments would have looked like had the discipline of competitive marketplaces not been introduced to the electricity industry and those who regulate it.

It is not competition that resulted in these costs. Rather, it is competition that brought light to the fact that the traditional cost-of-service regulatory model had resulted in uneconomic investments. The exact magnitude of these uneconomic investments is not known, but today we have estimated what the upper limits are.

This decision tackles very tough issues. It seeks to implement the various provision of state law that govern the recovery of uneconomic costs of the utilities. AB 1890 did not leave this Commission with much policy discretion with respect to so called transition costs. This decision applies the law to the facts.

Dated November 19, 1997 in San Francisco, California.

/s/ Jessie J. Knight, Jr.
Jessie J. Knight, Jr.
Commissioner

ALJ/ANG/wav/bwg

Mailed

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Decision 97-11-074 November 19, 1997

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

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

(See Appendix A for appearances)

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INTERIM OPINION: TRANSITION COST ELIGIBILITY

1. Summary

In this decision, we determine the eligibility of various categories of non-nuclear costs for transition cost recovery , consistent with the mandates of Assembly Bill (AB) 1890 and the Preferred Policy Decision (Decision (D.) 95-12-063, as modified by D.96-01-009). We establish the non-nuclear cost categories eligible for transition cost recovery and also quantify the net book value of various generation assets currently owned by Pacific Gas and Electric Company (PG&E), Southern California Edison Company (Edison), and San Diego Gas & Electric Company (SDG&E).[1] This net book value calculation is the appropriate starting point for market valuation, which results in a final determination of transition cost recovery for those assets subject to market valuation.

In the Preferred Policy Decision, we defined transition costs as the net above-market costs associated with uneconomic generation assets. Uneconomic assets are those assets whose net book value exceeds their market value. We established that each utility's net above-market costs would be determined after offsetting the benefits associated with economic assets against the excess costs of uneconomic assets. (Preferred Policy Decision, mimeo. at 116.) Eligible costs that do not undergo market valuation are compared to the Power Exchange market clearing price on an ongoing basis in order to determine the uneconomic portion. AB 1890 (Stats. 1996, Ch. 854,) affirmed our approach to transition cost recovery and added §§ 367 - 377 to the Public Utilities (PU) Code.[2] Much of the work in this phase, Phase 2, of this proceeding,

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[1] The Phase 1 transition cost issues were addressed in Decision (D.) 97-06-060, which established a transition cost balancing account for each utility and addressed various ratemaking issues related to the order in which revenues are applied to offset various transition costs. Transition costs for PacifiCorp are addressed in Application (A.) 97-05-011, for Sierra Pacific Power Company in A.97-06-046, for Kirkwood Gas & Electric Company in A.97-07-005, and for Southern California Water Company in A.97-08-064.

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

consists of establishing the baseline against which market valuation will later be measured and determining which eligible cost categories will be recovered on an actual, recorded basis, and which costs should be captured through the market valuation process. Many of the most contentious issues center on whether certain costs are "sunk" costs and therefore eligible for transition cost treatment, or whether such costs are "going forward" costs that should be recoverable from the new competitive generation market.

Work on Phase 2 began with an independent audit of the figures presented in the utilities' transition cost filings. The audit was performed by Mitchell Titus, LLP, with additional work by the Barrington-Wellesley Group, and was managed by the Commission's Energy Division. The purpose of the audit was to evaluate each utility's estimates of net book value and calculations of transition costs that have yet to be incurred. The independent audit was requested by several parties and ordered by Assigned Commissioner Ruling (ACR) dated August 1, 1997. That ruling recognized that while the audit is unlikely to resolve all of parties' concerns, it would prove a useful starting point for testimony on these issues, and would likely streamline the hearings considerably.

The utilities have presented the following amounts as non-nuclear costs eligible for transition cost recovery as of January 1, 1998. These figures do not include any assessment of the actual uneconomic value of such assets:

PG&E:	$35,413.351 million
Edison:	34,255.878 million
SDG&E:	3,483.777 million
Total:	$73,153.006 million

We emphasize that these are estimates of total costs proposed to be eligible for transition cost recovery.[3] In most cases, we do not forecast total transition cost recovery,

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[3] On a net present value basis, the utilities estimated the following amounts in transition costs, including nuclear assets:

Footnote continued on next page

which will ultimately be determined by the market valuation process, the Power Exchange price, and the limitations of the rate freeze, as discussed more fully below. Attachments 1 and 2 delineate the utilities' estimates of the magnitude of the uneconomic costs involved. Again, we emphasize that we are not approving such forecasts, but are providing these amounts for informational purposes. Only actual uneconomic transition costs will be recovered.

We do not address capital additions, which are being reviewed in a separate proceeding, nor do we address employee-related transition costs or restructuring implementation costs at this time. PG&E, Edison, and SDG&E shall establish subaccounts as placeholders in their transition cost balancing accounts to track recorded employee-related costs and any generation-related transition costs displaced due to recovery of restructuring implementation costs as defined in § 376. Actual employee transition costs will be reviewed in future annual transition cost proceedings. Restructuring implementation costs will be addressed in a separate proceeding, as will the market valuation procedures for retained assets.[4]

At the outset, it is important to note that the majority of costs eligible for transition cost recovery are prescribed by law. Costs related to nuclear generating assets and above-market contracts with Qualifying Facilities (QFs) account for the majority of estimated transition costs. Other than those costs related to on-going contractual obligations, most of the non-nuclear generation-related costs eligible for transition cost recovery are plant-related, which were verified by the transition cost audit. The majority of these costs are not challenged by any party.

PG&E - $11,300 million; Edison - $13,837 million; and SDG&E - $1,938 million, for a total of $27,075 million.

[4] Throughout these proceedings, we have anticipated additional phases to consider market valuation for retained assets and restructuring implementation costs. On January 1, 1998, the provisions of Senate Bill (SB) 960 becomes effective. Among other things, SB 960 establishes specific deadlines for handling proceedings. It is more efficient, therefore, to require PG&E, Edison, and SDG&E to file separate applications for each of these issues.

2. Background and Procedural History[5]

As defined in the Preferred Policy Decision, transition costs arise from generation assets, nuclear power plant settlements, power purchase agreements, QF contracts, and the reasonable costs of early retirement or retraining programs for employees. We defined uneconomic costs for generation assets as those occurring when the market value at the time of divestiture, spinoff, 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 invester-owned utilities (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. As directed by the Preferred Policy Decision and various rulings, Application (A.) 96-08-001, A.96-08-006, and A.96-08-007 were filed on August 1, 1996 by PG&E, Edison, and SDG&E, respectively. On August 30, PG&E, Edison, and SDG&E filed A.96-08-070, A.96-08-071, and A.96-08-072, respectively. These applications were consolidated by ruling.

On September 23, 1996, 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. On October 21, the utilities amended A.96-08-070, A.96-08-071, and A.96-08-072 to reflect the impact of and revisions required by AB 1890, specifically the requirements of newly added §§ 367, 368, 369, 372, 373, 374, 375, and 376.

A prehearing conference (PHC) in Phase 2 was held on January 21, 1997. The assigned Commissioners issued a ruling on February 4, which clarified the scope of

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[5] See D.97-06-060 for a more complete procedural history.

Phase 2 and established the procedural schedule.[6] The independent audit report was filed and served on March 21, 1997. PG&E, Edison, and SDG&E filed their responses to the audit report on April 10. Phase 2 testimony was served by the Office of Ratepayer Advocates (ORA), jointly by The Utility Reform Network (TURN) and the Utility Consumer Action Network (UCAN) (collectively, TURN), jointly by California Industrial Users (CIU), California Large Energy Consumers Association (CLECA), and California Manufacturers Association (CMA) (collectively, CIU), by the Federal Executive Agencies (FEA), jointly by the Energy Producers and Users Coalition (EPUC) and the California Association of Cogenerators (CAC) (collectively, EPUC), and jointly by Independent Energy Producers (IEP) and the California Cogeneration Coalition (CCC) (jointly, IEP). Rebuttal testimony was served on May 9. An additional PHC was held on May 15 and evidentiary hearings were held from May 19 through June 19. A Joint Comparison Exhibit (Exhibit 121) was filed on June 30. Concurrent opening briefs were filed by PG&E, Edison, SDG&E, ORA, TURN, CIU, FEA, the California Farm Bureau Federation (Farm Bureau), EPUC, and IEP on July 21. Reply briefs were timely filed by PG&E, Edison, SDG&E, ORA, TURN, CIU, FEA, EPUC, and Enron on August 1.

On July 16, 1997, we issued D.97-07-059 which directed PG&E, Edison, and SDG&E to establish memorandum accounts to track the differential between the authorized rate of return and the reduced transition cost rate of return, pending a finding on when the reduced transition cost rate of return should be applied. Pursuant to that decision, the administrative law judge (ALJ) directed interested parties to file and serve supplemental briefs on this issue by August 8. Reply briefs were filed and served on August 18.

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[6] In that ruling, the assigned Commissioners established that incremental capital additions made after December 20, 1995 would be considered in a separate proceeding. Accordingly, issues related to capital additions are not addressed in this decision.

In addition to the Phase 2 testimony and filings, we address certain policy issues raised in the Phase 1A briefs and reply briefs.[7] Briefs were filed on November 8, 1996 by PG&E, Edison, SDG&E, ORA, TURN (jointly with UCAN and the California Department of General Services), CIU, EPUC, the Farm Bureau, CLECA and CMA (jointly), and the California Energy Commission (CEC).[8] Reply briefs were filed on November 15 by PG&E, Edison, SDG&E, ORA, TURN, CIU, EPUC, CalEnergy Company, and the Coalition of California Utility Employees. Finally, we address comments by PG&E, Edison, and SDG&E as to factual eligibility issues, which were filed on February 14, 1997 in response to a joint Assigned Commissioners' and ALJ ruling issued on January 17. Responses to these comments were filed by ORA, TURN, and jointly by CIU, CLECA, CMA, EPUC, and CAC on February 28. The utilities filed reply comments to these responses on March 10, 1997.

3. AB 1890 and Transition Costs

As we discussed in D.97-06-060, AB 1890 adds several new sections to the PU Code, and endorses, for the most part, this Commission's approach to transition costs.[9] With certain exceptions, the legislation provides for a nonbypassable charge, the competition transition charge or 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 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

[7] Phase 1A established a briefing schedule to identify threshold policy issues that must be considered.

[8] EPUC filed a motion for leave to late-file its Phase 1A brief, which was filed on November 12. That motion is granted.

[9] Some of the sections added to the PU Code by AB 1890 have been subsequently amended by SB 477 (Stats. 1997, Ch. 275).

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 (i.e., generation assets, nuclear power settlements, power purchase contracts, and regulatory obligations), § 367 provides for transition cost recovery of costs associated with Biennial Resource Planning Update (BRPU) settlements, capital additions for units existing as of December 20, 1995 and which we find reasonable to maintain facilities until 2002, Edison's fixed fuel and fuel transportation contracts, and an expanded definition of employee-related transition costs. Section 367 also specifies the period during which particular transition costs may be recovered. Costs of generation-related assets and obligations must be collected by December 31, 2001, with the exception of certain nuclear settlements. 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 programs promoting renewable energy sources, or BRPU settlement costs, with certain additional provisions. Finally, § 376 provides that, to the extent that Federal Energy Regulatory Commission (FERC) or Commission-approved recovery of the costs of utility-funded programs to accommodate implementation of direct access, the Power Exchange, and the ISO reduces the ability of the utilities to collect generation-related transition costs, those generation-related costs may be collected after December 31, 2001, in an amount equal to the implementation costs that are not recovered from the Power Exchange or ISO.

Most importantly, in order to determine the transition costs for generation-related assets, we must net the above-market and below-market transition costs of all utility-owned generation-related assets. Valuation of these assets must occur by year-end 2001.[10] 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.

Section 330 expresses the Legislature's findings and declarations regarding electric restructuring. Section 330 has been included in order to provide guidance in carrying out the statutory provisions of restructuring. We quote relevant subdivisions below:

> "(d) The commission has found, after an extensive public review process, that the interests of ratepayers and the state as a whole will be best served by moving from the regulatory framework existing on January 1, 1997, in which retail electricity service is provided principally by electrical corporations subject to an obligation to provide ultimate consumers in exclusive service territories with reliable electric service at regulated rates, to a framework under which competition would be allowed in the supply of electric power and customers would be allowed to have the right to choose their supplier of electric power.
>
> "(e) Competition in the electric generation market will encourage innovation, efficiency, and better service from all market participants, and will permit the reduction of costly regulatory oversight."
>
> * * *
>
> "(2) Generation of electricity should be open to competition and utility generation should be transitioned from regulated status to unregulated status though means of commission-approved market valuation mechanisms.
>
> "(3) There is a need to ensure that no participant in these new market institutions has the ability to exercise significant market power so that operation of the new market institutions would be distorted.

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

"(n) Opportunities to acquire electric power in the competitive market must be available to California consumers as soon as practicable, but no later than January 1, 1998, so that all customers can share in the benefits of competition."

* * *

"(p) Consistent with federal and state policies, California electrical corporations invested in power plants and entered into contractual obligations in order to provide reliable electrical service on a nondiscriminatory basis to all consumers within their service territories who requested service.

"(q) The cost of these investments and contractual obligations are [sic] currently being recovered in electricity rates charged by electrical corporations to their consumers."

* * *

"(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, 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."

In order to lay the framework for our findings in this decision, we quote extensively from § 367, as amended by SB 477:

"The commission shall identify and determine those costs and categories of costs for generation-related assets and obligations, consisting of generation facilities, generation-related regulatory assets, nuclear settlements, and power purchase contracts, including, but not limited to, restructurings, renegotiations or terminations thereof approved by the commission, that were being collected in commission-approved rates on December 20, 1995, and that may become uneconomic as a result of a competitive generation market, in that these costs may not be recoverable in market prices in a competitive market, and appropriate costs 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 these additions are necessary to maintain the facilities through December 31, 2001. These uneconomic costs shall be recovered from all customers on a nonbypassable basis and shall:

"(a) Be amortized over a reasonable time period, including collection on an accelerated basis, consistent with not increasing rates for any rate schedule, contract, or tariff option above the levels in effect on June 10, 1996; provided that, the recovery shall not extend beyond December 31, 2001,...[with stated exceptions]

"(b) Be based on a calculation mechanism that nets the negative value of all above market utility-owned generation-related assets against the positive value of all below market utility-owned generation related assets. For those assets subject to valuation, the valuations used for the calculation of the uneconomic portion of the net book value shall be determined not later than December 31, 2001, and shall be based on appraisal, sale, or other divestiture. The commission's determination of the costs eligible for recovery and of the valuation of those assets at the time the assets are exposed to market risk or retired, in a proceeding under Section 455.5, 851, or otherwise, shall be final, and notwithstanding Section 1708 or any other provision of law, may not be rescinded, altered, or amended.

"(c) Be limited in the case of utility-owned fossil generation to the uneconomic portion of the net book value of the fossil capital investment existing as of January 1, 1998, and appropriate costs 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 these additions are necessary to maintain the facilities through December 31, 2001. All 'going forward costs' of fossil plant operation, including operation and maintenance, administrative and general, fuel and fuel transportation costs, shall be recovered solely from the independent Power Exchange Revenues or from contracts with the Independent System Operator, provided that for the purposes of this chapter, the following costs may be recoverable pursuant to this section:

"(1) Commission-approved operating costs for particular utility-owned fossil powerplants or units, at particular times when reactive power/voltage support is not yet procurable at market-based rates in locations where it is deemed needed for the reactive power/voltage support by the Independent System Operator, provided that the units are otherwise authorized to recover market-based rates and provided further that for an electrical corporation that is also a gas corporation and that serves at least four million customers as of December 20, 1995, the commission shall allow the electrical corporation to retain any earnings from operations of the reactive power/voltage support plants or units and shall not require the utility to apply any portions to offset recovery of transition costs. Cost recovery under the cost recovery mechanism shall end on December 31, 2001.

"(2) An electrical corporation that, as of December 20, 1995, served at least four million customers, and that was also a gas corporation that served less than four thousand customers, may recover, pursuant to this section, 100 percent of the uneconomic portion of the fixed costs paid under fuel and fuel transportation contracts that were executed prior to December 20, 1995, and were subsequently determined to be reasonable by the commission, or 100 percent of the buy-down or buy-out costs associated with the contracts to the extent the costs are determined to be reasonable by the commission.

"(d) Be adjusted throughout the period through March 31, 2002, to track accrual and recovery of costs provided for in this subdivision. Recovery of costs prior to December 31, 2001, shall include a return as provided for in Decision 95-12-063, as modified by Decision 96-01-009, together with associated taxes."

In building this framework, it is also useful to consider the Preferred Policy Decision. AB 1890 reflects several fundamental concepts articulated in the Preferred Policy Decision, in particular the concepts of netting economic and uneconomic costs, and minimization of transition costs:

"This netting of excess costs and benefits fairly reduces the overall level of the utility's transition costs. This netting of economic and uneconmic assets is also a partial way of compensating ratepayers for the loss of continued dedication to public use of economic assets.

"Offsetting uneconomic assets with economic assets is fair in another sense. . .The rate for electricity is thus an average reflecting the costs of

> both low-cost (economic) and high-cost (uneconomic) assets. It would obviously be unfair if, as part of our restructuring, we were to require customers to pick up the costs of high-cost generation without at the same time accounting for the benefits of low-cost generation." (Preferred Policy Decision, mimeo. at 118, 119.)

Section 367(d) specifically refers to the rate of return adopted in the Preferred Policy Decision. In discussing the principles underlying that reduced rate of return, we determined that ratepayers should benefit from transition cost recovery and that shareholders should recover lower revenues as transition costs than they would under traditional regulation. In particular, we determined that

> the assurance of full recovery gives the utility no incentive to minimize transition costs. This is counter to our goal of keeping transition costs as low as possible, but it has even worse implications. If the utility is indifferent to the level of transition costs, it would in turn have an incentive to bid low in offering its generation assets' output to buyers in the Power Exchange, with the forseeable effects of depressing the market-clearing price, squeezing the profit margins of competitors, and further increasing transition costs.

4. Need for Forecast of Transition Cost Amounts

PU Code § 370 provides:

> The commission shall require, as a prerequisite for any consumer in California to engage in direct transactions permitted in Section 365, that beginning with the commencement of these direct transactions, the consumer shall have an obligation to pay the costs provided in Sections 367, 368, 375, and 376, and subject to the conditions in Sections 371 to 374, inclusive, directly to the electrical corporation providing electricity service in the area in which the consumer is located. This obligation shall be set forth in the applicable rate schedule, contract, or tariff option under which the customer is receiving service from the electrical corporation. To the extent the consumer does not use the electrical corporation's facilities for direct transaction, the obligation to pay shall be confirmed in writing, and the customer shall be advised by any electricity marketer engaged in the transaction of the requirement that the customer execute a confirmation. The requirement for marketers to inform customers of the written requirement shall cease on January 1, 2002.

At the request of the ALJ, parties briefed the impact of this section on the need for forecasts of the transition cost obligation. Parties agree that, in general, there is no need for a forecast of either the total amount of transition costs or a particular customer's obligation. As discussed in D.96-12-077, D.96-06-060, and D.97-08-056, the rate freeze has created the concept of headroom, which results in the actual rate (the CTC) being computed residually. Because this rate is determined on a residual basis, there is no need to adopt specified transition cost forecasts or rate levels, as was originally conceived in the Preferred Policy Decision. In general, then, the actual transition cost amount will be determined from recorded levels, rather than forecast levels. On January 1, 1998, the recorded transition costs found eligible for transition cost recovery by this Commission will be debited, as appropriate, into each utility's transition cost balancing account. Revenues accruing from the CTC, the market, and the rate reduction bonds will also be tracked. As market valuation occurs for generation assets, corresponding credits will be booked into the transition cost balancing account. Thus, the need for forecasts, always a contentious process, is avoided.

The notice requirement of § 370 does not require a specific forecast of transition costs, but rather the notification that such charges will be made. As the Farm Bureau explains, § 370 should be read in conjunction with other components of the cost recovery plan set forth in § 368. Because § 368(b) requires that individual cost components be separately identified, the CTC must be residually established. Such a residual calculation, together with the rate freeze at June 10, 1996 levels, therefore precludes specifying particular amounts. If transition cost amounts are forecast and then allocated to each rate schedule, contract, and tariff option, the sum of CTC and other rate components, each of which would be allocated independently, based on different allocation methodologies, may be above or below the frozen rate levels. In addition, § 367(e)(1) requires that transition costs be allocated among customer classes, rate schedules, contract rates, and tariff options in substantially the same proportion as similar costs are recovered as of June 10, 1996. We concur that the necessity for forecasts of transition cost amounts is eliminated by the rate freeze and the residual calculation of the CTC. We will require that each utility implement clear, straightforward language in its tariffs, which notifies the direct access customer of the obligation to pay transition costs, consistent with our directives in D.97-06-060.[11]

5. Transition Cost Eligibility and Policy Issues

Generally, the utilities assert that all costs identified in their applications are recoverable as a matter of law under AB 1890. Several intervenors maintain that the Preferred Policy Decision specifically identified the concept of competitive neutrality regarding transition cost recovery and assert that costs which must be recovered by competitors in the marketplace should not be afforded transition cost recovery.

PG&E maintains that because every category of costs in its applications is either included in rates today or explicitly provided for in AB 1890, the Commission must determine that these costs are eligible for recovery as transition costs as a matter of law. Moreover, PG&E contends that it is not required to prove the facts associated with its claims for recovery to recover these costs, but that other parties must disprove these facts in order to advance their fact-based arguments against recovery of certain categories of costs. PG&E believes that if a cost is a generation-related cost or obligation and the cost is not an operating cost of a non-must-run fossil plant, the costs must be deemed eligible for transition cost recovery. PG&E contends that we do not have the authority under AB 1890 to declare that certain costs or cost categories are ineligible for transition cost recovery, because all such costs satisfy the test of eligibility described above.

PG&E believes that the concept of competitive neutrality should not enter into the determination of transition cost eligibility. PG&E states that transition cost recovery is allowed because the utilities are now required to adjust to a new regulatory

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[11] D.97-06-060 described two limited exceptions to the need for forecasts of transition cost amounts for departing load customers in order to calculate penalties for failure to pay CTC or failure to provide notice of departure from the system. Forecasts of customer transition cost obligations for these limited purposes will be determined in a later decision. Second, after 2001, transition cost obligations will decline significantly. D.97-06-060 recognizes that some customers may wish to resolve further CTC payments at that time.

framework, unanticipated when resource investment decisions were contemplated and because, until market valuation, the utilities are required to sell their plant output to the Power Exchange and are subject to administratively determined rates of return.

Furthermore, PG&E declares that many of the competitors expected to participate in the new market have various advantages and ways of recovering generation-related costs other than through Power Exchange revenues. For example, QFs recover costs pursuant to long-term contracts and thus will not have to recover all of their "going forward costs" from the Power Exchange. In-state municipal utilities have certain tax advantages and franchises under which they recover a large part of their costs. Out-of-state generators also have franchise customers from which large portions of costs are recovered. PG&E expects that these generators will not attempt to recover all of their sunk costs from the California market.

Edison agrees that the policy guidelines established by the Legislature and this Commission must be adhered to without further requirements being imposed. Edison argues that transition cost recovery was established to allow for recovery of costs associated with investments in plants and contractual obligations incurred in order to provide reliable, nondiscriminatory service. Edison explains that the term "competitive neutrality" has been used out of context and is used in the Preferred Policy Decision to explain only how the collection of CTC will be applied among customers, but does not refer to the various intervenor proposals that transition cost eligibility must exclude any costs that any of a utility's competitors must recover from the market.

SDG&E, too, agrees that the only relevant standards of eligibility are those expressed in AB 1890, which are consistent with the Preferred Policy Decision, and states that the cost categories that are the focus of other parties' concerns are all costs that are reflected in Commission-approved rates as of December 20, 1995. SDG&E contends that costs that may not have been recovered in rates are specifically provided for under either AB 1890 or the Preferred Policy Decision; e.g. employee-related transition costs, restructuring implementation costs, and BRPU buy-out costs. Thus, SDG&E contends there are no factual issues associated with eligibility, only with reasonableness and quantification.

As a matter of policy, the intervenors dispute the utilities' interpretation of eligibility. ORA strongly recommends that our policies be based on the idea that competition begins on January 1, 1998, rather than at the end of the transition period. ORA explains that the primary goals of its policy regarding restructuring are to ensure that the new electric markets work properly and that market forces operate to discipline and minimize the utilities' expenditures for transition costs. ORA therefore recommends that cost recovery for must-run plants should come from the must-run agreements with the ISO and any relevant Power Exchange revenues, rather than from transition cost recovery, and that the "going forward costs" of non-must-run plants must be recovered from competition in the market.

ORA asserts that determination of eligibility is not guaranteed, but is a multi-step process. ORA recommends that we consider the following threshold questions:

1. Is the cost category identified as eligible for transition cost recovery?
2. If eligible, are the costs in this category uneconomic?
3. Should these costs be classified as going forward costs for which recovery must come only through market revenues?
4. If a cost category is eligible and uneconomic, should recovery of this cost be accelerated?
5. What return should be authorized on the unamortized portion of the cost?
6. Does a specific cost item (as opposed to a cost category) meet the criteria required by AB 1890 or by the Commission?
7. Would inclusion of a category of classes exacerbate horizontal or vertical market power issues?

ORA agrees that several cost categories are clearly eligible for recovery as transtion costs. These include ongoing QF contract costs, sunk nuclear costs and incremental cost incentive pricing (ICIP) costs, transaction costs of divesting power plants, and transmission assets deemed generation plant (i.e., step-up transformers and generation radial tie-lines) by the Federal Energy Regulatory Commission (FERC).

TURN asserts that there are important policy issues that must be determined by this Commission, despite the guidance provided by AB 1890. TURN contends that the broad introductory language of § 367 must be interpreted consistent with the specific limitations provided in later portions of that section, particularly the prohibition in

§ 367(c) against recovering "going forward costs" from other than market revenues. Secondly, TURN recommends that the Commission consider the issue of economic or uneconomic assets on an overall basis; that is, if a generation facility is likely to be economic on an overall basis, specific costs associated with that plant should not be eligible for treatment as transition costs.

FEA recommends that several guidelines be adopted to determine eligibility criteria, including that the costs eligible for transition cost recovery must be prudent, that the basic purpose of such recovery is to mitigate the utilities' potential losses, that sunk transition costs must be supported by Commission decisions, that the utilities must mitigate their stranded costs wherever possible, and that competitive neutrality should be an important consideration.

CIU recommends structuring our policy regarding transition cost recovery to ensure that recovery is closely examined according to the underlying principle of competitive neutrality. CIU further explains that the limitations placed on transition cost recovery may lead to several costs claimed by the utilities that will not be recovered either in transition costs or in distribution rates, and that this outcome is consistent with the mandates of the law.

EPUC advocates that § 367 must be interpreted strictly and that the broad recovery alluded to in the first subdivision of § 367 is then limited by additional provisions regarding transition cost recovery, particularly in terms of fossil generation and net book value, as discussed more fully below. EPUC agrees with PG&E that where the Rate Restructuring Settlement (referred to in § 368(h)) conflicts with AB 1890, AB 1890 controls, but argues that the Rate Restructuring Settlement can provide guidance if there is ambiguity over what was intended by the statutory language.

Enron believes that the provisions of AB 1890 are intended to reflect a balance between the competing interests of ratepayers and shareholders and agrees that the central policy issue in Phase 2 is how the limitations expressed in AB 1890 will be applied to restrict the utilities' recovery of transition costs. Enron agrees with CIU that the concept of competitive neutrality is central to the principles delineated in the Preferred Policy Decision regarding transition cost recovery.

5.1. Discussion

We are mindful of the role of these proceedings: the Preferred Policy Decision has been issued; AB 1890 has been signed into law. The purpose of these proceedings is to implement the mandates of the various code sections, and where applicable, the requirements of the Preferred Policy Decision. We fully agree with Edison that this decision must execute Legislature's intent as expressed throughout the many PU Code sections added by AB 1890. However, we strongly disagree with the general assumption, as expressed by SDG&E that:

> In both the Preferred Policy Decision and AB 1890, the Commission and the Legislature expressed their unequivocal intent that it is both appropriate and necessary that utilities should recover all of their uneconomic costs associated with the transition to a competitive market. (SDG&E opening brief, p. 4)

In actuality, the utilities are merely allowed the *opportunity* to recover such costs, which are identified and determined by this Commission. The Legislature did not intend that we abrogate our authority in making such determinations. While we acknowledge the underlying principle that utilities should be allowed a fair opportunity to fully recover the uneconomic costs associated with generation-related assets and obligations, we must also recognize the Legislature's stated goals of implementing competition in the generation market and thereby allowing customer choice.

Our policy determinations are based on the tenets of the law and our preference for moving towards a competitive market as quickly as possible. As a general matter of public policy, we will balance the interests of both ratepayers and shareholders, while at the same time ensuring the viability of the nascent competitive marketplace. Our goal is to provide the utilities with a fair opportunity for full recovery of transition costs and to ensure that recovery of "going forward costs" is appropriately limited, consistent with the law. In this way, we will provide the utilities a fair opportunity to recover uneconomic costs, as required by law and policy, without impacting the competitive market and thereby insuring that recovery of transition costs, to the extent possible, will not decrease the competitive options available to customers.

We do not agree with Edison's contention that it is reasonable to aggregate fossil generation costs and revenues, in terms of tracking transition cost recovery. Instead, the assessment of whether assets and costs are economic or uneconomic must be made on an asset-specific basis. This methodology is required in order to carry out the netting principle; therefore, if a generation facility is likely to be economic on an overall basis, specific costs associated with that plant will not be eligible for treatment as transition costs. This principle has been debated thoroughly; indeed, we expressed our intent in this regard in D.97-06-060. A careful tracking of eligible transition costs and accrued revenues is necessary to ensure that we can confidently track recovery on an asset-specific basis. In order to apply the guidelines delineated in D.97-06-060, such detailed tracking is required. While § 367(b) requires a netting calculation, this certainly does not preclude asset-by-asset transition cost tracking, as Edison assumes. The expeditious, orderly recovery of transition costs, described in § 330(t) requires this approach.

6. Definitions

There is some argument as to basic definitions to be applied in this proceeding. Net book value has been defined in the Preferred Policy Decision and is used, but not defined, in AB 1890, specifically § 367(c). The term "sunk costs" is not defined in the Preferred Policy Decision, and is used only peripherally. It is neither used nor defined in AB 1890. PG&E suggests that defining such terms is not necessary at this time. We disagree. In such a complicated proceeding, it is pragmatic to ensure that all parties use the same terminology and understand such terms with particularity. By defining critical terms, we ensure that we are correctly applying the policy principles and foundation established in AB 1890 and the Preferred Policy Decision and at the same time, dispose of several contentious issues.

6.1. Net Book Value

Section 367(c) provides that uneconomic costs shall be "limited in the case of utility-owned fossil generation to the uneconomic portion of the net book value of the fossil capital investment existing as of January 1, 1998." Net book value was defined in the Preferred Policy Decision as follows:

> By "net book value," we mean the original cost recorded in the company's books for a particular asset less any accumulated depreciation and adjusted for deferred taxes, and any other asset or liability account which relates to the asset. (Preferred Policy Decision, mimeo. at 114, footnote 41.)

While PG&E does not believe it is necessary to adopt common definitions of these accounting terms, PG&E, Edison, SDG&E, and FEA recommend that this definition be used in determining transition costs. PG&E believes that this definition is consistent with § 367, but states that net book value does not encompass all of the costs that are eligible for transition cost recovery. In its Phase 1A policy brief, Edison clarifies that the phrase "any other asset or liability account which relates to the asset" would include all plant-related regulatory assets and liabilities, decommissioning, and deferred tax assets and liabilities. While Edison used the term "net book value" in A.96-08-006 in the more narrow sense as it is commonly defined, Edison now recommends that this definition be used only with the explicit recognition that costs included in the broader definition were eligible for recovery.

FEA recommends that the term include related decommissioning costs and costs of removal, as well as capital additions to generating facilities existing as of December 20, 1995, that the Commission determines are reasonable and should be recovered. ORA recommends that net book value be defined as the fully audited original costs recorded in each company's books for particular generation and generation-related plant, less any accumulated depreciation and adjusted for deferred taxes.

EPUC recommends that net book value be defined according to its common usage, i.e., as the original plant-in-service accounts costs less accumulated reserves for depreciation and amortization. EPUC believes that net book value is only a portion of "sunk" costs and is the definition underlying the language used in § 367(c). In its Phase 1A brief, EPUC explains that for purposes of AB 1890, net book value should not result in an amount that exceeds the original cost of an asset less depreciation and amortization. EPUC states that this counterintuitive result could occur if the overly-broad definition used in the Preferred Policy Decision is applied. For example, including other assets or liabilities associated with the plant (e.g., regulatory assets) or including going forward costs could lead to a higher value used to determine net book value. EPUC argues that the statute must govern and therefore the use of broad terms such as "any other asset or liability account which relates to the asset" would remove any meaning from § 367. EPUC further maintains that language in the Rate Restructuring Settlement can be used to clarify the Legislature's intent and that because the Rate Restructuring Settlement specifically distinguishes between the "net book value of fossil capital investment" and that of "fossil generation-related regulatory assets," the fact that § 367(c)(1) omits the latter phrase demonstrates the intent to limit fossil generation recovery to solely the net book value.

As discussed in the Phase 1A policy briefs, CEC recommends that we adhere to the definition of net book value, adopted in the Preferred Policy Decision and states that this definition is fully consistent with § 367. CEC also recommends that unless explicitly authorized in AB 1890 or eligible for recovery as an obligation or regulatory obligation, no going forward generation-related costs should be eligible for transition cost recovery. CLECA and CMA caution that adopting a definition does not eliminate the need to apply informed judgment to various cost categories, and furthermore, that this should be done on a case-by-case basis. While CLECA and CMA agree with the Preferred Policy Decision's definition of net book value, they believe that judgment must be applied to distinguish assets that are directly related to the generation asset from those that are indirectly or remotely related.

We will adopt a definition of net book value, but agree with CLECA and CMA's recommendations; i.e., we will apply informed judgment to the various cost categories for which the utilities seek transition cost recovery. We agree with Edison that the Legislature has forged California's electric restructuring policy in the context of the Commission's work in this regard, as acknowledged in § 330(d). Where specific terms are not defined, we must apply our broad knowledge of ratemaking principles and policy to interpret the statute in our administrative role to "supervise and regulate every public utility in the State and ... do all things, whether specifically designated in this part or in addition thereto, which are necessary and convenient in the exercise of such power and jurisdiction." (§ 701.) In this instance, it is reasonable to assume that the Legislature's intent in using the term "net book value" was based on the more narrow definition, because it refers specifically to the net book value of fossil *capital investment*.

However, because § 367 begins with a recitation of our duties in determining those costs and categories of costs for "generation-related assets and obligations, consisting of generation facilities, generation-related regulatory assets, nuclear settlements, and power purchase contracts...," it is unambiguous that such assets were intended to be eligible for transition cost recovery. We will apply the definition of net book value as original cost less accumulated depreciation and amortization in determining eligibility of various costs and cost categories for transition cost recovery, but will do so using the informed judgment and careful review recommended by CLECA. In order to implement this policy, we will fully and appropriately account for the impact of deferred taxes on the net book value quantification.

6.2. Sunk Costs

PG&E defines sunk costs to include generation-related costs that have occurred in the past, such as investments in generation-related plant and regulatory assets, or are fixed generation-related future obligations, such as fuel transportation costs and decommissioning costs. Edison thinks that sunk costs and net book value are equivalent terms, as provided in the Preferred Policy Decision; furthermore, Edison states that because AB 1890 does not use this term and because the statute governs which categories of costs should be recoverable as transition costs, it is not necessary to define this term for purposes of this proceeding. SDG&E believes that sunk costs include not only the net book value of non-nuclear generation and generation-related assets, but also obligations such as the unavoidable expenditure of funds for purchase power contracts and for other commitments related to generation operations.

ORA states that sunk costs are costs incurred in the past, which are non-recurring and best reflected by the net book value of utility assets. FEA asserts that sunk costs are generation-related costs that are fixed and unavoidable, but are not necessarily synonymous with transition costs that are to be recorded through the transition cost balancing account. FEA cites examples of sunk costs, including the original costs of generation facilities less depreciation, regulatory assets and liabilities which represent costs or obligations incurred in the past but which have not yet been fully recovered in rates, and generation-related costs associated with existing plant investments that will be incurred in the future, such as non-nuclear decommissioning costs.

CIU recommends that sunk costs in this context should be defined as capital costs only, using the net book value as of December 31, 1995, brought forward to January 1, 1998, and cites D.89-12-016 as defining sunk costs as those that have already been invested in plant. (34 CPUC 2d 55, 62.) Thus, CIU believes that PG&E's definition of sunk costs is too broad and that, although certain future costs are recoverable as transition costs pursuant to AB 1890, those costs cannot be considered sunk costs since they have not yet been invested in plant. EPUC states that sunk costs are those non-recurring generation facility, generation-related regulatory asset, nuclear settlement, or purchase power contract costs that were incurred and authorized for recovery in rates prior to December 20, 1995 and which were reflected in rates effective on June 10, 1996, with the caveat that none of these costs may be classified as "going forward" costs. EPUC believes that sunk costs and net book value are not synonymous and moreover, this definition is not relevant for transition cost eligibility purposes. EPUC recommends that we reject SDG&E's proposed definition of sunk costs because it is so broad as to render § 367 meaningless.

As addressed in the Phase 1A policy briefs, CEC defines sunk costs as those costs incurred in the past, in contrast to incremental and imputed costs. Such costs appear in accounting records, but are irrelevant for future operating decisions of the company. CEC agrees with ORA that sunk costs and net book value should be used synonymously. CLECA and CMA think that adopting a definition for sunk costs is not useful in this context, particularly because it is not used in AB 1890 and appears to be used synonymously with net book value in the Preferred Policy Decision. CLECA and CMA stress that just because a cost is categorized as sunk does not automatically mean that it is eligible for CTC recovery.

We agree that, in this case, it is not particularly advantageous to adopt a definition of sunk costs. This term was used only peripherally in the Preferred Policy Decision and was not used at all in AB 1890. It is more useful simply to define the terms that are actually used in the statute, but in order to establish a commonality of terms in this proceeding, we will define sunk costs as those which have already been expended for capital investment purposes. In D.97-05-088, we implicitly defined sunk costs when we stated, "the sunk costs for which PG&E now seeks recovery represent its undepreciated capital costs in the plant." (D.97-05-088, mimeo. at p. 31.) We explicitly defined sunk costs as "costs which are already incurred that can no longer be avoided or reduced through a curtailment or reduction of output or by providing other means of furnishing the service." (*Id.*, p. 41.)

6.3. Going Forward Costs

In general, recovery of going forward costs must be achieved by means of market revenues. The term "going forward costs" is used in § 367, but is not defined by the legislation, which states that "[a]ll 'going forward costs' of fossil plant operation, including operation and maintenance, administrative and general, fuel and fuel transportation costs" must be recovered through market revenues or ISO contracts, with certain important exceptions. Section 390(g) addresses short-run avoided costs and also uses the term "going forward costs:"

> The term "going forward costs" shall include, but not be limited to, all costs associated with fuel transportation and fuel supply, administrative and general, and operation and maintenance; provided that, for purposes of this section, the following shall not be considered "going forward costs": (1) commission-approved capital costs for capital additions to fossil-fueled power plants,

> provided that such additions are necessary for the continued operation of the power plants utilized to meet load and such additions are not undertaken primarily to expand, repower or enhance the efficiency of plant operations; or, (2) commission-approved operating costs for particular utility-owned power plant units and at particular times when reactive power/voltage support is not yet procurable at market-based rates in locations where it is needed, provided that the recovery shall end on December 31, 2001.

Edison points out that going forward costs can only be incurred by investor-owned utilities when those utilities are providing fossil-fired electric generation, beginning on January 1, 1998. Edison also states, however, that the utilities will incur certain fossil generation-related costs on and after January 1, 1998, regardless of whether they are still providing fossil generation to the market, including environmental compliance costs, pensions, and certain post-retirement benefits which must be provided even if all gas-fired generation were to cease.

EPUC argues that going forward costs are not limited to only incremental, variable costs or expense-related, non-capital costs, but that the statute implies that all going forward costs, both fixed and variable, are to be excluded from transition cost recovery; i.e., all costs that are necessary for the continued or future operation, maintenance or termination of the facility must be recovered from Power Exchange or ISO revenues.

Again, we must define going forward costs for purposes of ensuring that transition cost recovery is in compliance with the law. As in our discussion of net book value, we will use the context of the Preferred Policy Decision to inform our understanding and interpretation of AB 1890. We define going forward costs as all costs necessary to continue to operate the plant or unit. Going forward costs may include both fixed and variable costs. This interpretation most closely matches the standards articulated in the statute and our own preference for market recovery of such costs.

In D.97-08-056, our unbundling decision, we found that the definition of "going forward costs" was not limited to incremental costs and we recognized that, over time, all successful competitors must recover all costs, including fixed costs. It is for those reasons that we declined to allocate all fixed costs to distribution customers, which would then create a competitive advantage for the IOUs. (D.97-08-056, mimeo. at pp. 22-23.) Therefore, going forward costs will be defined as all costs that are necessary for the continued or future operation of the plant or unit, and include, but are not limited to, all costs associated with fuel transportation and fuel supply, administrative and general, and operation and maintenance, with the statutory exceptions established in § 367(c)(1) and (c)(2).[12]

6.4. *Must-run Generating Plants*

As CIU explains, "must-run" has been used as a general term to distinguish generating plants (or units within plants) that must be available to provide energy or ancillary services (in particular, reactive power/voltage support, one of a number of ancillary services) on a localized basis in order to maintain grid reliability.[13] Several aspects to the must-run determination must be considered. First, units may be deemed must-run for locational purposes; i.e., these units are within an area constrained due to transmission congestion and must be run to provide energy within the constrained area because sources of generation outside the constrained area do not have access to that area, because of transmission congestion.

Second, units may be deemed must-run for reliability purposes. These units provide voltage control and reactive power. These units are designated must-run for reliability purposes due to the requirements of the grid system for voltage and stability. To add to the complexity, units may serve dual functions. FERC has confirmed that the ISO should determine which plants are needed to provide reactive power/voltage support and when, because the ISO "will have the necessary information and technical expertise to make the determinations, and it will have no

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[12] In D. 97-09-048, our decision on capital additions, we determined that capital additions occurring after January 1, 1998 to must-run plants should be recovered from payments under the ISO reliability contracts or Power Exchange revenues.

[13] We distinguish here between must-run and must-take resources. Must-take resources were defined in the Preferred Policy Decision and include QFs, nuclear, hydro-spill, and preexisting power purchase contracts with minimum take requirements.

incentive to discriminate among generators." (*Pacific Gas and Electric Company*, 77 FERC ¶ 61,265, December 18, 1996)."

On March 31, 1997, the ISO Trustee submitted descriptions of three types of Pro Forma Master Must-Run Agreements as part of its Phase II filing at FERC. The agreements are identical for PG&E, Edison, and SDG&E. As stated above, the ISO will determine which plants are must-run. According to the Phase II filing, the ISO intends for the must-run agreements to be temporary measures to be replaced as soon as possible by purchases either by solicitation or through the open market. The ISO recommends that it be authorized to terminate any must-run agreement upon 90 days' notice if it finds a less expensive source to supply this reliability power. It is important to emphasize that FERC may, of course, reject or modify these recommended agreements. However, it is pertinent to consider the interaction of such contracts and transition cost recovery. As a general rule, if the ISO agreements allow costs to be recovered as an ISO expense, they should obviously not be recoverable as transition costs.

Under all three agreements, the designated must-run units receive payments for start-up, fixed, and variable costs. Fixed costs include both a portion of existing rate base and incremental capital costs deemed acceptable by the ISO. We described these proposals in D.97-09-048:

" FERC included the following discussion in its December 18, 1996 order:

> "Must-run generating units: These are units that must be dispatched during certain hours for reliability purposes, regardless of the units' bids. As a result of...physical limitations, during those hours, markets are sub-divided and isolated. Must-run units could be considered an extreme case of horizontal market power where, due to system conditions, the geographic market is so reduced that the system operator must run the units in order to satisfy demand that is assumed to be unresponsive to price. The operators of these units would have market power because there are no other alternatives. Therefore, if they had market-based rates, they could bid very high prices and the ISO would have to dispatch them at those prices." (*Id.* at pp. 62,076-77.)

> To summarize, the ISO proposes three types of reliability contracts, identified as Agreements A, B, and C. Agreement A assumes that the plant is economic and the ISO simply purchases needed resources at market prices. The owner can sell additional resources over and above the needs of the ISO (e.g., spinning reserves, voltage support, energy) into the Power Exchange. Agreement B provides for negotiated terms whereby the owner may have the right to collect revenues above what it might otherwise get above a market-based rate. In particular, Agreement B provides for a fixed cost payment and operating cost payment up to 100% of the cost of providing the needed must-run services to the ISO. Agreement B allows the plant to operate during hours when not needed by the ISO, but credits most of the profits from such operations to the fixed cost component. Agreement C is a cost-of-service contract for uneconomic units that must run for reliability reasons and are not likely to run during other hours. The units under this agreement are prohibited from supplying power during hours when the ISO does not need them. (D.97-09-048, mimeo. at p. 14.)[15]

As proposed, with a 90-day notice period, a plant owner may request a transfer to Agreement B or Agreement C. In addition, the ISO may transfer a plant to Agreement B or a negotiated version of that contract, on its own initiative, with 90 days notice. If the ISO refuses the owner's request, the existing agreement ends and the unit is no longer must-run. If the owner wishes to switch to Agreement B, the ISO can require that the owner negotiate to be paid any share of fixed costs that would be larger than would have been paid under Agreement A.

On October 30, 1997, FERC issued its "Order Conditionally Authorizing Limited Operation Of An Independent System Operator And Power Exchange, Conditionally Authorizing Transfer of Control Of Facilities On An Interim Basis To An Independent System Operator, Granting Reconsideration, Addressing Rehearings, Establishing Procedures and Providing Guidance," Pacific Gas and Electric Company,

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[15] We note that an application for rehearing of D.97-09-048 has been filed by PG&E. The determinations of this opinion do not prejudge the issues raised in that application for rehearing.

San Diego Gas & Electric Company and Southern California Edison Company, Docket Nos. EC-96-19-001 *et al.*, 81 FERC ¶ 61,122, 1997). In this order, FERC provides interim and conditional authorization under sections 203 and 205 of the Federal Power Act to the ISO and the Power Exchange to commence their operations, including interim conditional authorization of market-based rates for the Power Exchange.

FERC has accepted the pro forma Must-Run Agreements for the interim period, subject to certain modifications. FERC has required that the ISO file changes to the Agreements, as the ISO has proposed to do, by October 31, 1998, at which time FERC will re-evaluate the Agreements.[16]

For our purposes, we need only define must-run units in terms of which operating costs of which plants are eligible for transition cost recovery, pursuant to § 367(c)(1). Non-must-run plants are those generating plants which are not required to be available by the ISO for reliability purposes. The specific language of § 367(c)(1) makes it clear that the only units to which the statute refers are those units providing reactive power/voltage support, i.e., those units which must be run to support the reliability of the grid. We note that the precise language used in § 367(c)(1) confirms the wording of the Preferred Policy Decision, in which we determined that it is necessary to "severely limit... utilities' ability to obtain operating costs through the transition cost balancing account for their nonnuclear units" and determined that "[t]he only operating costs eligible for that account must be demonstrably necessary for reactive power/ voltage control." (Preferred Policy Decision, mimeo. at p. 100.) In addition, we determined that it was necessary to limit transition cost recovery of operating expenses in order to mitigate cross-subsidization and prevent utilities from exploiting regulated

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[16] FERC has not yet ruled on the selection of must-run units because the selection and criteria used for selecting units for must-run status has not yet been filed by the ISO. When this is filed, FERC will evaluate the selection of must-run units based on certain criteria, including an agreement in principle that the ISO should consider all costs when selecting units for must-run status, including stranded costs. (*Id.*)

markets to obtain leverage in competitive markets. (Preferred Policy Decision, mimeo. at p. 102.)

6.5. *Obligations*

Both AB 1890 and the Preferred Policy Decision refer to "generation-related assets and obligations." Although not addressed to any extent in Phase 2, this term was defined by various parties in Phase 1A. Again, defining this term with specificity will assist us in our policy determinations. The Preferred Policy Decision specifically cites regulatory obligations as a category eligible for transition cost recovery. Regulatory obligations are

> "primarily related to various deferred costs and outstanding balancing account balances 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...but *these amounts should relate only to the generation assets affected by this restructuring.*" (Preferred Policy Decision, mimeo. at pp. 133 - 134, emphasis added.)

Contractual obligations are also defined in the Preferred Policy Decision in conjunction with QF contracts and other power purchase agreements. Section 367 refers to generation-related assets and obligations. Although "obligations" is not defined in § 367, again, we refer to the Preferred Policy Decision to frame the context in which legislative discussions were held and to enlighten our determinations. While AB 1890 discusses contractual obligations specifically, we cannot infer that regulatory obligations were intended to be excluded from transition cost recovery. In interpreting the statute, we will follow the California Supreme Court's guidance that:

> "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.)

Furthermore, we have stated in D.97-06-060 that because there is no specific reference to accounting methodology in AB 1890, we rely on our knowledge of current ratemaking practices, common sense and our duty to further the public interest in carrying out the mandates of the law. We find that both regulatory obligations and contractual obligations are eligible for transition cost recovery, in conformance with § 367. However, we will carefully review each claim for transition cost recovery in this category to determine whether such assets and obligations are, in fact, generation-related, unavoidable, and uneconomic.

7. 150 Basis Points Mechanism

The Preferred Policy Decision considered the recovery of transition costs, including operating costs:

> "All other costs of running [fossil fueled] units, including capital costs not yet incurred, will be subject to recovery through the prices received from the Exchange, with one limited exception. For those units that are primarily needed for reactive power/voltage control, if the costs of running these units (including capital costs not yet incurred) exceed the Exchange clearing price, utilities may seek partial recovery of operating costs up to the year 2003, subject to performance-based ratemaking, until or unless market based prices for reactive power/voltage control are set by the FERC. Further, if no recovery for reactive power/voltage control is sought and the Exchange clearing price exceeds the costs of running these units (including capital costs not yet incurred), utilities may retain profits providing up to 150 basis points above their authorized return for distribution rate base. Any further profits will be used to reduce CTC." (Preferred Policy Decision, mimeo. at p. 135.)

We determined in D.94-04-042 that the 150 basis point mechanism does not apply to non-must-run units:

> "AB 1890 addresses capital additions, but is silent on the 150 basis points allowance described above, other than for PG&E. Section 367(c)(1) provides that earnings from PG&E's reactive power/voltage support

> plants or units will be retained by PG&E and not used to offset transition cost recovery. A question that arises is whether fossil units which are not deemed needed for reactive power/voltage support...are eligible for the 150 basis points allowance. Edison's and PG&E's applications reflect the position that these units are eligible. We hold, however, that they are not. (D.97-04-042, mimeo. p. 17.)
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> "We intend that the 150 basis points allowance which was adopted in the Preferred Policy Decision will be applied only to fossil units which are primarily needed for reactive power/voltage control." (*Id.*, Conclusion of Law 3, p. 22.)

PG&E filed a petition in A.96-07-009 *et al.* (the PBR proceeding related to generation assets) for reconsideration of this issue. We affirmed our previous findings in D.97-07-037. We have previously stated that we would not address the merits of this issue in this proceeding, but we will consider the calculation of the 150 basis points mechanism and the interaction of this mechanism with transition cost recovery.

7.1. The Utilities

PG&E, Edison, and SDG&E are not claiming the 150 basis point mechanism for their must-run plants at this time. As discussed above, the development of this incentive or a similar incentive which would apply to non-must-run plants is to be determined in another proceeding. To the extent that such an incentive is applicable, PG&E recommends that the amount be determined at the time of market valuation based on costs tracked in plant-specific memorandum accounts. Edison and SDG&E recommend that the incentive be calculated annually if market revenues exceed incremental costs. Edison would include the calculation of an incremental capital cost credit prior to the application of the 150 basis point mechanism.

7.2. Intervenors

ORA recommends that any portion of the 150 basis point mechanism ultimately authorized in the PBR proceeding should be applied only after accounting for all going forward costs. TURN supports ORA's position and particularly emphasizes that the 150 basis points should be applied only after the utility recovers all of its operations and maintenance and fuel costs. TURN further recommends that no

150 basis point allowance should be paid for any plant asset if the utility is recovering any fuel-related costs for that plant in the transition cost balancing account. CIU believes that developing an implementation procedure here is premature, since it is unknown whether the substantive mechanism (as proposed by the utilities) will be approved in the generation PBR proceeding. EPUC recommends that this mechanism not be allowed for either must-run or non-must-run plants. To the extent that such a mechanism is developed, EPUC recommends that the applicable amounts be determined at the time of market valuation based on costs tracked in plant-specific memorandum accounts.

7.3. Discussion

We have previously determined that the 150 basis point mechanism applies only to must-run units. While the utilities dispute this approach, the merits of applying this incentive to the non-must-run units is not being considered here. We agree with ORA and CIU that it is premature to develop an implementation methodology at this time. If we reconsider this issue in the generation PBR proceeding, we can address implementation and interaction with transition cost recovery at that time. However, we provide some guidance in this area and find that should such an incentive mechanism be developed and adopted, all going forward costs must be accounted for with market revenues before any type of incentive mechanism should be applied.

8. Ratemaking treatment of gain or loss on sale

PG&E explains that the gain or loss on sale of depreciable assets has traditionally been flowed back to ratepayers through the depreciation reserve, while gains or losses related to non-depreciable property have been allocated to shareholders. PG&E believes that land must now be treated as depreciable property because of the language adopted in the Preferred Policy Decision and AB 1890. Therefore, PG&E proposes that all gains and losses realized through sale, spinoff, or appraisal of generation assets, including land, should flow back to ratepayers by way of the transition cost balancing account.

At the time of divestiture, Edison proposes to deduct the transaction costs of the sale from the sale proceeds. Edison would then compare this net sales revenue amount to the unamortized sunk cost of the asset at the time of sale to determine the net gain or loss on sale. Edison proposes to amortize this gain or loss on sale in the transition cost balancing account over the remaining months from the time of sale to December 31, 2001. Edison proposes that the unamortized portion of the gain or loss would be subject to the reduced rate of return and that the amortization would be accelerated according to the guidelines of D.97-06-060. Edison believes this approach is consistent with the requirements of § 367(b), which states in relevant part that uneconomic costs shall "be based on a calculation mechanism that nets the negative value of all above market utility-owned generation-related assets against the positive value of all below market utility-owned generation related assets." SDG&E agrees that the transition cost balancing account will provide the proper mechanism for netting the undepreciated book value against the market value.

Conceptually, we agree that the gain or loss resulting from sale of assets, including land, should now flow through the transition cost balancing account, but we see no reason to adopt Edison's approach of amortizing any gain over the remaining months of the transition period. The gain should simply be credited to the transition cost balancing account and the appropriate subaccount closed out.

We are currently authorizing auctions for assets undergoing divestiture. Pursuant to § 367(b), the valuation of these assets, in proceedings under §§ 455.5, 851, or otherwise, is final. As we move forward with these auctions, we must carefully review the transactions to ensure that the maximum amount reasonable under the circumstances of the sale is obtained to offset transition cost recovery, as is our duty under of AB 1890. For those assets which are retained by the utilities, we will develop market valuation procedures for appraisal, as discussed above.

9. Transition Cost Ratemaking and Market Power

In D.97-06-060, we adopted a transition cost balancing account for each utility and described in general terms how the recovery of various costs would be tracked in that account. In this decision, we discuss this recovery more specifically, particularly in terms of tracking the costs and revenues related to plants designated by the ISO as necessary for reactive power/voltage support and the non-must-run plants. As we have summarized, at least initially, the utilities are expected to have some locational market power, and this expectation has resulted in three call contracts being proposed to FERC. Agreements A, B, and C were described in Section 6. According to the proposals made at FERC, the ISO could terminate any existing ISO contract with 90 days' notice.

The actual tracking and accounting for transition costs and revenues associated with must-run units and non-must-run units is complicated; similarly, the issues raised in this area are complex and interrelated. First, we discuss transition cost ratemaking in terms of tracking and recording costs and revenues, recording net book value and depreciation, and applying various revenue crediting mechanisms. Next, we address the interaction of transition cost recovery and market power concerns in the context of transition cost ratemaking. We will explain the parties' positions in each of these areas and then discuss our determinations concerning transition cost ratemaking as a whole.

9.1. Tracking and Recording Costs and Revenues

PG&E proposes that prior to market valuation, all market revenues less operating costs be tracked in plant-specific memorandum accounts. At the time of market valuation, any credit balances resulting from operating profits would be credited to the transition cost balancing account. PG&E states that it reserves the right to seek recovery of debit balances for the must-run plants and would ask that we review the reasonableness of such recovery.

PG&E contends that based on the full context of § 367(c)(1), for fossil generating plants, it is the uneconomic portion of the net book value of the capital investment as of January 1, 1998,, and necessary capital additions to maintain the facilities through December 31, 2001 found reasonable by this Commission, which are recoverable from all customers on a nonbypassable basis. In addition, PG&E asserts that operating costs such as operation and maintenance (O&M), administrative and general, and fuel and fuel transportation costs are recoverable as transition costs if they are incurred while providing must-run services for the ISO and the plant is otherwise authorized to recovery market-based rates. PG&E thus believes that the implication is that if ISO contracts do not adequately cover the fixed and operating costs, such recovery may be sought elsewhere, including through the transition cost balancing account.

PG&E states that it has not created any subaccount in the transition cost balancing account to recover the operating expenses for non-must-run plants. PG&E intends to track fixed and variable operating costs and revenues for both must-run and non-must-run plants in separate memorandum accounts until market valuation occurs for each plant. PG&E proposes to track operating expenses for both non-must-run and must-run plants based on actual, recorded fuel costs and to track other expenses according to allocations adopted in A.96-12-009 *et al.* Tracking these costs and revenues will allow PG&E to compute the credit amount, if any, to account for revenues in excess of operating expenses for both the must-run and non-must-run plants. PG&E proposes that the resulting credit, if any, accrue to the transition cost balancing account, but PG&E recognizes that it is at risk for costs to the extent that operating expenses exceed revenues for non-must-run plants.

PG&E disputes CIU's contention that all capital costs associated with must-run plants with contracts with the ISO should be recovered only from the ISO revenues. PG&E contends that this would be contrary to § 367(c) unless it was assumed that such costs were economic. PG&E maintains that CIU's concerns are based on whether the mixture of transition cost recovery and ISO revenues could lead to double recovery of these costs, which PG&E asserts are ameliorated by its tracking proposal, since the ISO revenues would be credited back to transition cost recovery.

Edison recommends tracking all costs and revenues in fossil subaccounts of the transition cost balancing account, based on recorded amounts. These entries would include all plant-related capital costs, O&M costs, fuel costs, dispatch costs for gas, and ISO and Power Exchange revenues. Edison proposes to use recorded costs even for those cost categories that are subject to separate reasonableness reviews and that may be subject to pending reviews when the entries to the transition cost balancing account are being determined. Edison believes this is necessary because costs must be recovered prior to December 31, 1997 and such reasonableness reviews can be lengthy.

However, Edison states that the costs to be recovered through the balancing account would not exceed the sum of costs eligible for recovery. Edison explains that its proposal includes the relevant costs associated with must-run units as part of the costs eligible for recovery through the transition cost balancing account and establishes a crediting mechanism which includes the revenues from the ISO for the must-run services. Edison recommends this approach because this methodology would not require modification if the structure of the proposed ISO agreements should be modified by FERC. Edison contends that this proposal provides the opportunity to recover costs eligible for transition cost recovery, but there is no double recovery.

Edison has proposed a complicated revenue crediting mechanism to ensure that all costs and revenues are debited and credited correctly. First, Edison defines net eligible transition costs (i.e., costs eligible for transition cost recovery) as plant-related sunk costs, incremental capital costs necessary to maintain the facility through 2001, fixed fuel and fuel transportation costs for contracts signed prior to December 20, 1995, and Commission-approved operating costs for must-run generation, net of the market value of emissions allocations and revenues from gas sales. Once this determination is made, Edison proposes calculating three different credits: 1) for both must-run and non-must-run units, a gas purchase credit, which is defined as the market (or dispatch) costs of gas less the actual variable costs of gas; 2) an incremental capital cost credit to be applied to the non-must run units, and 3) a Power Exchange/ISO revenue credit to be applied to the must-run and non-must-run units. Edison proposes allocating the Power Exchange/ISO revenues net of going forward costs for the non-must-run units first to the incremental capital cost credit, the 150 basis points earnings mechanism, and then to the Power Exchange/ISO revenue credit (non-must-run). For the must-run units, Edison proposes that Power Exchange/ISO revenues net of going forward costs not found eligible for recovery through the transition cost balancing account be allocated to the Power Exchange/ISO revenue credit (must-run). The gas purchase credit, incremental capital cost credit, and Power Exchange/ISO revenue credits are then added together. If this result is positive, the amount is credited to offset costs eligible for transition cost recovery.

Edison contends that ORA's proposal to exclude sunk costs associated with must-run generating units from the transition cost balancing account has no applicability to must-run generation undergoing divestiture. In addition, Edison contends that it is only the future avoidable costs of a unit rather than the sunk costs, that are relevant in deciding whether it is efficient to replace that unit with a new entrant; therefore sunk costs are irrelevant in making economically efficient decisions. Edison agrees with CIU that § 367(c)(1) does not apply to Agreement C, because under this agreement, owners are not allowed to participate in the competitive market. Edison also agrees that the utilities should not have the opportunity to double recover costs, but believes this problem is averted by separately identifying the costs recoverable through the transition cost balancing account and then including the revenues received under the ISO must-run contract as a form of revenue in determining the Power Exchange/ISO revenue credit.

SDG&E proposes to record must-run costs and revenues in the transition cost balancing account while under Agreement A or until such time as Agreements B or C become available options. At that time, the accounting treatment would change to a memorandum account to be trued-up as part of the market valuation process. SDG&E proposes that the costs be audited and the revenue treatment be reviewed annually for those costs and revenues receiving balancing account treatment. SDG&E states that must-run costs should include those fixed costs required for maintaining plant availability requirements and the variable costs incurred as the units are dispatched. SDG&E contends that the proposed must-run agreements do not change the language of § 367(c)(1),which specifically allows for transition cost recovery of Commission-approved operating costs of those plants deemed by the ISO as needed for reactive power/voltage support.

For non-must-run units, ORA recommends that crediting Power Exchange revenues in excess of going forward costs to the transition cost balancing account. Consistent with its preferred methodology, ORA contends that going forward costs include all fuel, O&M costs, administrative and general costs, and depreciation and return on off-site common and general plant and capital additions. In contrast to PG&E and Edison, ORA proposes that no fuel or fuel transportation contract costs be included in the transition cost balancing account. These costs should be recovered from the Power Exchange and ISO to the extent possible. For Edison, if Power Exchange revenues are insufficient to cover all fuel, O&M, and capital additions costs, ORA recommends that only the fuel costs associated with fixed demand charge or take-or-pay provisions should be recoverable through the transition cost balancing account, and then, only to the extent that such fuel costs are uneconomic. This amount would be limited to the difference between Power Exchange revenues and all going forward costs, including capital additions. If the Power Exchange revenues exceed all these costs, no fuel costs could be added to the transition cost balancing account and a revenue credit would be available.

For must-run units, ORA recommends that the ISO revenues in excess of going forward costs should accrue to the utility and should not be credited to the transition cost balancing account unless the unit's must-run contract is terminated. Any profits should be tracked in a memorandum account should this event occur. ORA asserts that placing the fixed costs of must-run units in the transition cost balancing account would create a locational market power problem and inhibit the development of competitive markets for must-run reliability power. If the plant owner knows that fixed costs are covered in the balancing account, the owner may be inclined to accept less than full recovery of fixed costs through a must-run agreement. This, in turn, could create a locational market power problem by inhibiting market entry by new units in the same geographic area. ORA argues that because proposed Agreements B and C provide the plant owner with the opportunity to recover all fixed capital costs, including sunk costs, the sunk costs of must-run units should not be included in the transition cost balancing account. Once the agreement is terminated, the fixed capital costs associated with that plant should be calculated as the net book value as of January 1, 1998 less the fixed capital costs recovered under the reliability contract from must-run payments or from market revenues. This amount would then be booked to the transition cost balancing account. ORA thus recommends that while Agreement A may not cover all capital costs, any shortfall should be remedied by negotiating a transfer to Agreements B or C, rather than by guaranteeing recovery through the transition cost balancing account. ORA recommends that costs and revenues used to calculate profits should be tracked separately in memorandum accounts for non-must-run units and must-run units, which would then facilitate reasonableness reviews.

TURN states that operating costs of the must-run and non-must-run units are not eligible for transition cost recovery, but are going forward costs. To the extent that costs in excess of the Power Exchange prices are recovered through the ISO, they should be recovered from customers in transmission rates, rather than through transition cost recovery.

CIU asserts that there is no utility right to reserve the option to seek recovery of debit balances for must-run plants, unless that plant is actually called upon for reactive power/voltage support (and not any other "must-run" purpose) and the ISO fails to fully compensate the utility for such use. CIU states that § 367(c)(1) provides only limited options for transition cost recovery for must-run plants and contends that the utilities do not distinguish particular reasons for a plant being must-run, which could include purposes other than reactive power/voltage support, as described in the statute. CIU further maintains that to the extent the ISO limits payments to plants or units providing reliability support, it is not certain that the utilities have the right to seek recovery of additional costs through the transition cost balancing account. CIU believes that what is paid according to the ISO agreements must be considered sufficient to provide for the availability of resources to meet must-run needs related to reactive power and voltage support; therefore, there should be no additional recovery of operating costs through the transition cost balancing account. In addition, CIU asserts that because Agreement C does not allow for market-based rates and is cost-of-service based, § 367(c)(1) would not allow recovery of operating costs for plants covered by Agreement C.

EPUC recommends that generating units designated for reactive power/voltage support should not receive any transition cost recovery for any costs incurred during particular hours when the ISO did not require the unit to operate in order to provide this support. Thus, EPUC recommends that the accounting for these must-run units must ensure that all going forward costs are ineligible for transition cost recovery during the particular hours these units are not needed by the ISO for local reliability/voltage support. EPUC suggests that for purposes of transition cost accounting, revenues sufficient to cover costs should be imputed to each utility, thus ensuring that the daily net revenues are always greater than zero. EPUC believes that over a daily period, this approach is more likely to ensure that there is no systematic bidding below cost into the Power Exchange.

9.2. Recording net book value and depreciation

PG&E plans to track monthly recorded rate base for its fossil generation power plants, beginning January 1, 1998. These recorded rate base amounts will be based on eligible recorded plant, net of accumulated depreciation and recorded inventory balances, adjusted for accumulated deferred taxes. PG&E also proposes to ratably amortize generation-related assets and obligations. PG&E proposes that the recorded rate base balances reflect the amortization of uneconomic plant and plant-related costs, based on the 48-month schedule adopted in D.97-06-060.

Edison suggests basing the January 1, 1998 entries to the transition cost balancing account on recorded plant, depreciation reserve, and deferred tax balances as of that date, in order to maintain consistency among entries and related accounts. Edison proposes this approach for post-1995 capital additions, despite the fact that such additions will be reviewed in a separate proceeding, and recommends making adjustments, if necessary, to true-up the balancing account once final determinations have been made in that proceeding. Edison agrees that it is reasonable to use the 1995 year-end net book value amounts to begin the amortization schedule, as proposed by ORA, but recommends that the associated depreciation and deferred tax computations must also reflect year-end 1995.

SDG&E explains that it will reflect the amortization of the uneconomic portion of eligible plant using the 48-month amortization period adopted in Phase 1 and clarifies that as transition revenues are applied against these costs, generation rate base will be reduced on a comparable basis.

ORA does not agree with utility proposals to record and amortize the economic or uneconomic sunk costs of both must-run and non-must-run plants in the transtion cost balancing account. ORA recommends that only non-must-run sunk costs should be amortized in the transition cost balancing account. For must-run plants, ORA proposes that these sunk costs be amortized in the transition cost balancing account only until Agreements B or C become available and after such contracts are terminated for a particular unit.

9.3. Revenue Crediting Mechanisms

Revenue crediting mechanisms address how to apply each utility's revenues from the sales of electricity and ancillary services to its various costs. Neither PG&E nor SDG&E proposes any revenue crediting mechanisms. PG&E explains that its approach of using memorandum accounts to track the difference between operating expenses and revenues for both must-run plants and non-must-run plants, and to credit the revenues in excess of expenses and any allowed 150-basis point provision will eliminate the need for any revenue crediting mechanisms. PG&E is not claiming the 150 basis point mechanism for its must-run units, nor is PG&E planning on retaining any earnings from the operations of the reactive power/voltage support plants or units, although § 367(c)(1) allows those earnings for PG&E. As part of PG&E's proposal both in this proceeding and before FERC, that any excess revenues above operating costs would be credited to offset transition cost recovery. PG&E proposes to track costs and revenues through appropriate plant-specific memorandum accounts and then to do a one-time accounting at the time of market valuation of that plant to determine if there are any eligible costs that PG&E wishes to recover in the transition cost balancing account. PG&E recognizes that it must apply revenues from fossil plants which are in excess of costs to offset transition costs and proposes to do so in a memorandum account. PG&E also recognizes that operating costs and going forward costs of non-must-run plants cannot be included in the transition cost balancing accounts for recovery.

Edison explains that in general market revenues will be allocated to its revenue requirements, with any balance applied to reduce transition costs. Edison explains its approach to calculation of eligible transition costs as a series of interrelated steps. Edison goes through a multi-step process to derive its proposed revenue credit for non-must-run plants (with revenues deriving from both non-must-run gas plants and coal plants (all of which are non-must-run). Edison essentially would flow all its costs and revenues through the transition cost balancing account. Market revenues are first allocated to recover all going forward costs, then to incremental capital additions, then to its proposed 150 basis point earnback mechanism and finally to calculating a credit from the excess market revenues, if any, to be applied as a credit to the transition cost balancing account. Edison's proposal is similar for its must-run plants, except that no 150 basis point earnback is proposed.

Edison also states that because, in its filing at FERC, it has committed to a variable cost floor calculated over a two-week period on the revenues it can receive from its gas generation prior to divestiture, it is precluded from bidding below variable cost into the Power Exchange. Edison therefore disagrees with EPUC's contention that the revenue crediting mechanism never be permitted to go negative in any single day. Edison states that the reason the variable cost floor is defined over a two-week period is to consider the impact of the costs of starting and stopping a generating unit, which are generally committed to participate in a market over a multi-day period. In other words, Edison maintains that EPUC's proposed daily calculation provides too short a time frame for calculating the net revenue credit, because the utility may not recover its no-load and start-up costs on a daily basis.

Because we have not adopted a 150 basis point incentive mechanism for non-must-run units, ORA states that its proposed revenue crediting mechanisms and those of Edison are now not very different. ORA proposes a revenue crediting mechanism for all three utilities and wants to be certain that proper accounting of these mechanisms is established in the event the 150 basis point mechanism is adopted for non-must-run plants, such that all going forward costs are covered before any profits accrue to shareholders. ORA further wants to ensure that such mechanisms require that the utilities recover all going forward costs from market revenues in order to have the utilities bidding into the Power Exchange at fair levels. ORA proposes that its revenue crediting mechanism apply to non-must-run units and former must-run units whose contracts with the ISO have been terminated. Thus, for must-run units under Agreements B or C, ORA recommends that the utilities track costs and revenues in memorandum accounts to result in future revenue crediting if the unit terminates its ISO must-run contract during the transition period.

ORA explains that for a market to be sustainable, the market clearing price must be set high enough to allow economically efficient non-utility generators to recover all economic capital costs and operating expenses associated with owning and operating the unit over its lifetime. ORA fears that if the utilities can cover these costs through transition cost revenues and various revenue crediting mechanisms, this could result in the utilities bidding into the Power Exchange at an artificially low price. Thus, competitors would be disadvantaged, increasing the utilities' market power. Excess revenues result from the difference between bid prices and the market-clearing price and it is through this surplus that fixed capital costs and fixed expenses are covered. ORA explains that excess revenues remaining after paying operating costs are available to pay capital costs, including depreciation first, and then return on the asset. Therefore, ORA recommends that we should not allow transition cost recovery of economic costs, i.e., those costs that can be recovered through the market.

ORA maintains that these costs must be netted out of market revenues prior to crediting any excess revenues to the transition cost balancing account. Consistent with its position on these issues, as discussed more fully below, ORA advocates that economic fixed fuel costs and the depreciation and return on off-site common and general plant and capital additions also be subtracted from market revenues prior to any revenue crediting. For sunk generating plant, ORA maintains that as the unit ages, the market value decreases, thus increasing transition costs. The depreciation on the economic portion of the plant, then, should be recoverable from market revenues, which ORA believes will parallel the decrease in market value.

ORA explains that another reason for crediting excess market revenues to offset transition cost recovery is that prior to market valuation, the uneconomic portion of the plant is not known. Thus, the reduced rate of return can be applied only to the entire plant and charged to ratepayers through the CTC. The market revenue credit would compensate for this so that ratepayers would pay a return only on the uneconomic portion of the plant, while the market paid for the return on the economic portion. The revenue credit implicitly includes this return on the economic portion and would then offset the return on the total plant, because this is part of the transition cost revenue requirement.

EPUC recommends specific modifications to Edison's revenue crediting proposal. As discussed in Section 13, regarding fuel and fuel transportation contracts, EPUC maintains that Edison's gas purchase credit should have a safeguard and never be recorded as less than zero. Without this safeguard, EPUC believes Edison would recover more than the statute allows for the uneconomic portion of the fixed gas costs.

9.4. Market Power and Transition Cost Recovery

The Assigned Commissioners issued a ruling on February 4, 1997, which established, among other things, that transition cost recovery raises fundamental questions related to competition and the interaction of transition costs with the operation of the Power Exchange:

> "While it is FERC which will decide the particular horizontal and vertical market power issues and appropriate mitigation measures, this Commission has stated clearly in several forums that it will be actively concerned with market power in its own proceedings. (Preferred Policy Decision, mimeo. at 20; Roadmap 2 decision, mimeo. at 9.) Therefore, as we begin Phase 2 of the transition cost proceedings, we will ask parties to consider and respond to issues related to transition cost recovery, market power and incentives which may be operating in the short term and the long term. For example, one such issue we wish to consider is whether recovery of transition costs under the rate freeze creates any perverse effects in the Power Exchange; i.e., does the existence of headroom lead to

predatory pricing, and if so, how can this effect be mitigated." (Joint Assigned Commissioners' Ruling, February 4, 1997, at p. 9.)

Several pages of written testimony addressed this issue. In consultation with the Assigned Commissioners, the ALJ struck much of the testimony which related to specific findings that must be made by FERC or which would require findings that were not relevant to this proceeding. (RT: 1319-1320.)

PG&E maintains that there are no market power issues to address regarding transition cost recovery, because all such issues are being considered at FERC. PG&E also states that because Edison plans to divest all of its gas-fired plants and PG&E has now pledged to divest 100% of its fossil plants, market power concerns would be short term in nature.

Edison disputes CIU's assertion that must-run units receiving fixed-cost recovery through call contracts with the ISO will have a competitive advantage over other generators bidding into the Power Exchange. Edison believes that this allegation is not relevant to this proceeding because these issues are being considered at FERC and because any concerns would be short-lived, due to its agreement to divest its gas-fired plants. Edison argues that in a competitive market, the recovery of fixed costs should not influence short-term pricing decisions. Edison agrees with SDG&E that, because FERC will only grant market-based pricing authority if the utility demonstrates that market power has been adequately mitigated, utilities will not have the market power to depress market prices. Edison explains that the transition cost mechanism will not provide for the recovery of operating losses, because going forward costs (other than for must-run units) must be recovered from the market.

Edison disputes ORA's proposal to exclude sunk costs associated with must-run generation from the transition cost balancing account, because this proposal does not recognize that sunk costs are irrelevant in making economically efficient decisions and because it should have no applicability to must-run generation undergoing divestiture.

SDG&E maintains that nothing in the transition cost recovery mechanism would influence its market power position. SDG&E explains that while during the rate freeze, SDG&E prefers that Power Exchange prices be lower in order to maximize its available headroom, this should not be construed as predatory pricing. SDG&E recommends that any policy regarding competition must exist to protect competition and consumers, rather than particular competitors. SDG&E observes that the rate freeze should eliminate concerns regarding predatory pricing. Predatory pricing is defined in this context as a market power concern arising from a hypothetical possibility that a seller with large market share would sell below variable cost in order to drive competitors from the market. At that point, the seller would recoup its losses by charging exploitative high prices. If there is no ability to recoup lost profits by subsequent high prices, consumers would not be damaged and would benefit from the period of low bidding into the Power Exchange. Furthermore, SDG&E contends that, because of its small size, it lacks market power, other than local market power in the San Diego Basin which would be mitigated by the proposed must-run contracts.

ORA asserts that market power can result when costs that should be recovered in the marketplace are in fact recovered through the transition cost mechanism. This could lead to depressed bidding prices into the Power Exchange, leading to deflated market clearing prices, which could then disadvantage other competitors. ORA believes that this potential also exists in the ISO market for reliability services. Given that fewer producers will likely compete in local areas for reliability services, ORA contends that this is the more critical area. ORA recognizes that divestiture will mitigate many market power concerns in this area, but asks that the policy for transition cost recovery for must-run units (most of which are fossil) be established so as not to create or exacerbate any market power concerns.

ORA suggests that to mitigate such market power concerns in the ISO reliability market, no transition cost recovery should be allowed for must-run units. ORA explains that the proposed Agreements B and C are intended to grant full cost-of-service recovery, including sunk capital costs. Hence, if recovery of these costs is then permitted in the transition cost balancing account, there would be little incentive for the utilities to negotiate properly with the ISO. However, to conform to the requirements of

§ 367(c)(1), ORA would allow transition cost recovery for must-run plants during the first 90 days on Agreement A while a switch to Agreement B is being sought.

ORA urges us to require all non-must-run units to recover their going forward costs from the Power Exchange, as required by § 367(c). ORA recommends that while this is required by law only for fossil units, market power concerns prescribe that the going forward costs of hydroelectric and geothermal units which are retained should also be recovered from the market. ORA also recommends allowing transition cost recovery for Edison's uneconomic and reasonable fixed fuel and fuel transportation costs only to the extent that Power Exchange revenues do not cover all fixed and variable fuel, O&M costs, and administrative and general costs.

FEA urges us to ensure that the transition cost balancing account not include any costs which are not specifically required under AB 1890. Similarly, EPUC recommends that the proper standard to bear in mind in considering market power issues is that the market should be equal for all new market competitors, which cannot occur if utility assets are not at risk for going forward costs consistent with the requirements of § 367(c). EPUC maintains that the utilities' proposed accounting mechanisms and safeguards with regard to must-run operating cost recovery would lead to market distortions. EPUC strongly recommends that we ensure transition cost recovery for must-run units only at the particular hours when the unit is providing local reliability/voltage support and that otherwise such units not be permitted to distort the competitive market by bidding into the Power Exchange during non-constrained-on hours. EPUC asserts that the utilities' fossil units represent marginal generation much of the time and therefore, if the units bid their actual operating costs these units would establish the Power Exchange clearing price. EPUC fears that if must-run units can receive cost recovery through transition cost recovery, this would result in the market clearing price being set by a lower-cost producer and recommends that these distortions be avoided by ensuring that the costs of those must-run units which the utility chooses to place at market risk should be barred from transition cost recovery.

IEP explains that the rate freeze, the residual CTC calculation, and the existence of headroom all combine to create a strong incentive for the utilities to deflate

Power Exchange prices, which would then lead to dampened competition. Consequently, although the rate freeze protects consumers from high prices, IEP contends that they are still harmed because if competitors are driven from the market and new entry is discouraged, there will be no choice among energy service providers after the transition period. This lack of competition could then result in higher prices after the rate freeze, because there will not be competition to ensure that energy prices are driven down to marginal costs. IEP asserts that despite the fact that FERC has jurisdiction over the market power issues brought before that agency in regard to establishment of the ISO and Power Exchange, we are also obligated to consider these issues and their impact on competition.

IEP asks that we consider its proposals for market power mitigation in this proceeding, despite the fact that its prepared testimony regarding divestiture and the establishment of a total cost bidding floor was stricken. IEP is not necessarily suggesting we adopt its proposed solutions in this proceeding; rather we could order divestiture or adopt a bid floor in a separate proceeding. We affirm that the ALJ properly struck this testimony and we will not address IEP's proposed mitigation measures in this proceeding. This proceeding is complicated enough without considering additional complex issues that are being addressed elsewhere and will be decided in other forums. Furthermore, on July 30, FERC issued an order providing guidance to the ISO and Power Exchange governing boards and required the restructuring proposal to be refiled on August 15, 1997, along with various additional submissions, including various monitoring and mitigation proposals regarding market power. (FERC ¶ 61,128, mimeo. at p. 1.) It would be premature to address these issues in this proceeding.

9.5. Discussion

We fully support the idea that the linchpin of competition policy must be to protect competition and consumers, rather than individual competitors. In order to ensure that competition exists and to protect the incipient competitive generation market, we must ensure that no greater competitive advantage is afforded the incumbent utilities than any other competitor in the new market. As discussed in the Preferred Policy Decision, we have adopted transition cost recovery for several vital reasons, including acknowledging the regulatory compact in existence at the time investment decisions were made, and this policy has now been mandated by law. In implementing this policy, however, we are also compelled to ensure that we foster competition as the new competitive marketplace begins to function. It is for these reasons that we address the interaction of transition cost ratemaking and market power concerns.

We are disturbed by the idea of tracking all costs related to non-must-run and must-run units through the transition cost balancing account, whether various revenue credits are applied to those costs or not. Our concern centers on the possibility of allowing recovery of going forward costs through transition cost recovery, when that is contrary to the concept of fostering a competitive marketplace and is specifically prohibited by law, with only limited exceptions. Although accounting for such costs and revenues in memorandum accounts is cumbersome, we are prepared to require such tracking. The interaction of transition cost recovery and market prices is significant and may be critical to the successful operation of the marketplace.

We have stated many times that we wish to avoid administrative calculations of transition costs to the extent possible and prefer to rely on market mechanisms. We are spurred in this regard by the Legislature's affirmations that competition in electric generation is preferred to regulation because it will encourage innovation, efficiency, and better service from all market participants. (§ 330(e).) ORA's discussion regarding the treatment of excess revenues is important, although we disagree with its recommendations. We agree that market revenues from all sources, that are in excess of costs should ultimately offset transition costs. These revenue sources include all revenues from the Power Exchange and the ISO, but may also include revenues from other markets, or sources as may be determined in the future.[17]

On the whole, we agree with PG&E's approach, with certain modifications. We direct the utilities to establish separate memorandum accounts for non-must-run and for must-run plants. For the non-must-run plants, we will track the difference between costs and market revenues on a monthly basis. Any excess revenues will be credited to offset transition costs on an annual basis, in the following fashion. The revenues will be tracked in the memorandum account on a monthly basis and will be available to apply to costs incurred in other months. Any excess revenues accruing in a particular month will earn the reduced transition cost rate of return, rather than the commercial paper rate. We recognize the utilities' concerns that monthly postings of excess revenues to the transition cost balancing account could impact the recovery of costs incurred during plant outages when there may not be revenues to offset these costs. An annual crediting to the transition cost balancing account of any excess revenues addresses such concerns. At the same time, applying the reduced rate of return to these revenues is appropriate because this higher interest rate compensates ratepayers for carrying costs associated with transition costs that would otherwise have been reduced through monthly postings. No interest rate or rate of return will be applied to any debit balances in that account.

PG&E, Edison, and SDG&E should establish a Power Exchange Revenue Memorandum Account to track actual going forward costs on a plant-specific basis. PG&E has proposed to use this approach for fuel costs, but to base other operating costs on revenue requirements adopted in D.97-08-056. We prefer a more accurate approach. Information regarding operations should be readily available. The utilities should then

[17] For example, currently pending before FERC are proposed ISO and Power Exchange tariffs for various markets, which will produce revenues from Supplementary Energy Bids, Ancillary Service Bids, Adjustment Bids (for congestion management), and Imbalance Bids. If approved by FERC, these revenues, or revenues from any other such as ISO or Power Exchange auctions approved by FERC, must be tracked for purposes of transition cost recovery.

credit the transition cost balancing account for any excess market revenues greater costs, including revenues from the ISO, Power Exchange and other retirement sources, as described above. If revenues are less than costs, no additional transition cost recovery is allowed, consistent with § 367(c), nor will any interest be allowed on debit balances in this tracking account.

In D.97-09-048, we determined that the costs of capital additions incurred after January 1, 1998 should be recovered from market revenues, rather than through transition cost recovery. We have allowed limited ex post facto reasonableness reviews of these expenditures for transition cost recovery if and only if the following four conditions are met: 1) the capital additions were made to ISO-designated must-run units and were necessary to continue operating the must-run unit during the transition (through December 31, 2001), 2) the capital additions were cost-effective compared to other options for maintaining plant operations through the transition and compared to other resources available to the ISO for system reliability, 3) the final ISO contracting options approved by FERC did not include provisions that would allow utilities to negotiate recovery of these costs and 4) the costs of capital additions could not be recovered in market prices for energy or ancillary services. Furthermore, we have determined that the ISO contracts afford the utilities the opportunity to recover the costs of capital additions needed to maintain system reliability. Establishing a procedure for this recovery at this Commission would be inefficient and could also give the utilities a competitive advantage over other providers of must-run units and thwart our objective of creating a level playing field.

Similar principles apply to recovery of operating costs. These contracts did not exist when AB 1890 was signed into law. The contracts have been proposed to FERC to ensure that the reliability of the grid will not be compromised. To the extent the ISO limits payments to plants or units providing reliability support, we do not agree that the utilities have the right to seek recovery of additional costs through the transition cost balancing account. Given the jurisdiction of FERC over the ISO, and the fact that FERC has allowed the ISO to make these determinations, the amounts paid according to the ISO agreements should be considered sufficient to provide for the availability of resources to meet must-run needs related to reactive power and voltage support; therefore, in general, there should be no additional recovery of operating costs through the transition cost balancing account.

We do not think that Agreement A should necessarily be subject to the § 367(c)(1) exception. Rather, we are persuaded that under the proposed Contract A, the ISO is paying for a pro rata share of the fixed costs of a competitive plant, as well as for its variable costs when the plant is called upon by the ISO for must-run purposes. This merchant plant is expected to recover its other costs in the marketplace. We must presume that the variable costs paid by the ISO for these purposes must be sufficient to recover the operating costs for those units needed for reactive power/voltage support at particular times. It is possible that under Agreement A, the utilities will not recover all operating costs related to reactive power/voltage support. Rather than seeking transition cost recovery, however, one solution is for the utility to negotiate with the ISO to move to Contract B. Agreement B provides specifically for recovery of fixed costs, which include sunk costs; therefore, to the extent that sunk costs are recovered through ISO revenues, there should certainly be no duplicate recovery through transition cost recovery. We agree with CIU that because Agreement C does not allow for market-based rates and is cost-of-service based, § 367(c)(1) would not allow recovery of operating costs for plants covered by Agreement C.

Certainly, the only instance in which we would even consider transition cost recovery for must-run plants is for those particular units operating at those particular times when the plant is actually called upon for reactive power/voltage support (and not any other "must-run" purpose), and the ISO contract has not provided recovery of operating costs, and the units are otherwise authorized to recover market-based rates. Therefore, while the task may be complicated, we must ensure that we can clearly track and distinguish the costs for those units designated by the ISO as necessary to operate at particular hours for reactive power/voltage support from units designated as must-run for any other purposes, in order to allow operating cost recovery for those units the guidelines of § 367(c)(1). The utilities will have the burden of clearly distinguishing and demonstrating particular reasons for a plant being operated for only reactive power/voltage support, consistent with the other criteria described in the statute. We will consider such recovery only for these units on Agreement A during the first 90 days of the transition period.

We are reluctant to flow these costs and revenues through the transition cost balancing account, because of the potential for double counting, despite Edison's assurances to the contrary. Instead, we prefer PG&E's proposal and direct each utility to establish an ISO Revenue Memorandum Account for its must-run plants and to track market revenues, as described for the non-must-run plants. We will review the memorandum accounts and their ultimate transfer to the transition cost balancing account, if appropriate, in the annual transition cost proceedings. This review process will provide the utilities with the assurance that, to the extent that uneconomic costs and operating costs of must-run units on Agreement A are not covered by ISO and other market revenues, they will have the opportunity to present and clearly prove the reasonableness of these costs to this Commission.

However, we do not agree with ORA that transition cost recovery of sunk costs for must-run units should be precluded. It is not clear that the ISO Agreements will provide for recovery of all sunk costs, although certainly a portion of sunk cost recovery will occur. In essence, the proposed contracts will allow for the "economic" depreciation and return on investment of these plants. We will account for this by crediting excess revenues to the transition cost balancing account.

FERC has accepted the pro forma Must-Run Agreements on an interim basis, but requires the ISO to file revised Agreements by October 31, 1998. These revisions include clarifications and modifications to Agreements A, B, and C. (Pacific Gas and Electric Company *et al.*, 81 FERC ¶ 61,122, 1997, mimeo. at p. 257.) These memorandum accounts will allow the necessary tracking to occur so that any required modifications to our procedures can be executed efficiently and easily.

One purpose of the memorandum accounts is to track the going forward costs and market revenues for particular assets and to verify that market revenues which are greater than costs are credited appropriately to the transition cost balancing account. Pursuant to the guidelines established in D.97-06-060, the transition cost balancing account will track current costs eligible for transition cost recovery, including scheduled amortization. The transition cost balancing account also tracks CTC revenues, the market revenues related to a particular asset less going forward costs, as discussed above, and market valuation credits.

In addition, we will establish procedures to complete the market valuation process as early in the transition period as possible. All generation assets owned by the utilities must be market valued by December 31, 2001, consistent with § 367(b), by divestiture, appraisal, or other form of sale. Nothing in the legislation, however, precludes us from requiring that this market valuation occur before that date. Early market valuation will ensure that the transition to a competitive generation market is completed as expeditiously as possible.

Initiating the market valuation procedures early in the transition has at least two important advantages. First, market valuation gives us the necessary information regarding economic and uneconomic costs for these assets and will assist us in ultimately determining both the final amount of transition costs allowed for generation plant assets and when the rate freeze can end. Second, once market valuation occurs and the rate freeze ends, it will no longer be necessary to track excess revenues accruing from market revenues.

Divestiture proceedings are well underway for PG&E and Edison. Edison plans to divest 100% of its gas-fired fossil plants and will retain its hydroelectric and coal plants. PG&E has now pledged to divest 100% of its fossil and geothermal plants. It is equally important to develop appraisal procedures for those plants which are retained by the utilities. We will initiate this proceeding by requiring PG&E, Edison, and SDG&E to file applications by March 2, 1998 which identify the plants they plan to retain, proposed guidelines for appraisal, and a proposed procedural schedule for addressing these issues.

The January 1, 1998 entries to the transition cost balancing account should be based on recorded plant, depreciation reserve, and deferred tax balances as of December 31, 1995, to maintain consistency among entries and related accounts. In other words, the net book value as of December 31, 1995, of eligible plant categories will be amortized over the 48-month transition period according to the guidelines established in D.97-06-060. These amounts will then be trued-up for 1996 and 1997 capital additions, because such additions will be reviewed in a separate proceeding. Adjustments and true-ups for depreciation will occur in the annual transition cost proceeding. These recorded rate base amounts will be based on eligible recorded plant, net of accumulated depreciation and recorded inventory balances, adjusted for accumulated deferred taxes. The initial recorded rate base balances will reflect the amortization of uneconomic plant, based on the 48-month schedule adopted in D.97-06-060. As provided for in that decision, assets should not be depreciated below market value, which will account for recovery of the economic portion of the depreciation in the marketplace. Amortization schedules should be recalibrated, as necessary. As the divestiture proceedings progress, many of our concerns regarding must-run plants will be eliminated through the market valuation process. The utilities may adjust the transition cost balancing account when assets are sold or market-valued to reflect the actual costs on the books. If decisions regarding capital additions are issued after the sale of a plant, the transition cost balancing account will be adjusted to reflect the outcome of those proceedings.

Because we have prescribed various guidelines in D.97-06-060 regarding order of recovery and acceleration, we are not as concerned about capturing the economic value of depreciation through the market. While we have determined that the net book value is eligible for recovery at the beginning of the transition period, we have also stated that each asset should be depreciated to its market value, but not below, and that recalibration of the amortization may then be necessary.

10. Transition Cost Audit

In response to an Assigned Commissioner Ruling issued August 1, 1996, the Commission Advisory and Compliance Division (predecessor to the Energy Division) coordinated the selection of an independent auditor to establish the net book value of the non-nuclear generation assets and other transition costs, as a starting point in determining the transition cost estimates. Mitchell & Titus, LLP and the Barrington-

Wellesley Group, Inc. were engaged to perform the audit and produce a report, "Agreed-Upon Special Procedures Review of Unrecorded Sunk Costs and Future Costs for PG&E, Edison, and SDG&E. This report was filed and served on March 21, 1997. The auditors issued an audit opinion on the recorded sunk cost balances of transition costs reported by the companies as of December 31, 1995. The audit opinion for each utility was qualified with respect to inventory balances, because of the auditors' inability to observe physical inventories on December 31, 1995. In addition, for PG&E, the audit opinion as of December 31, 1995 was qualified for the Western Area Power Administration (WAPA) regulatory asset balance of $137.1 million because of a scope limitation due to insufficient supporting information being provided by PG&E. The audit opinion for PG&E was also qualified for the QF Buyout regulatory asset account balance of $165.1 million, because approval is pending before the Commission. Other than these exceptions, the audit opinion for the recorded sunk cost balances as of December 31, 1995 was unqualified. Certain immaterial errors were identified at PG&E and Edison which did not result in a qualification of the audit opinion.

The auditors also reviewed unrecorded sunk costs as of December 31, 1995 and future cost balances projected as of January 1, 1998 and presented a report on these balances. The auditors questioned various costs of each utility in the following categories:

1. AB 1890 definition: The category includes costs questioned by the auditors because they are not in strict compliance with AB 1890.
2. Commission approval: The category includes costs incurred prior to December 20, 1995 that are not included in rates and have otherwise not been approved by the Commission.
3. Estimates and Assumptions: This category relates primarily to future costs, which were questioned because they were either based upon speculative assumptions or because the auditors could not adequately test the company's estimates.
4. Inadequate support: These costs are questioned because the company did not supply the information necessary to test the amounts included in the transition cost filing.

5. Company adjustments: This category reflects adjustments proposed by the company based upon information which became available after the date of the transition cost filing.
6. Accounting problems: This category represents costs which are questioned because of accounting errors or other reporting problems.

The following table shows the results of the auditor's review:

Summary of Questioned Costs by Category

(Dollars in Millions)

Description	PG&E	Edison	SDG&E	Total
Amount recorded on the Transition Cost Statement	$ 35,393	$ 34,239	$ 3,521	$ 73,153
Items not authorized specifically in AB 1890	$ 91	$ 64	$ 39	$ 194
Items Lacking Commission Approval	$ 81	$ 632	$ -	$ 713
Items that used questionable Estimates & Assumptions	$ 1,516	$ 2,313	$ 24	$ 3,853
Items lacking adequate Support	$ 1,917	$ 444	$ 10	$ 2,371
Adjustments made by the Utilities	$ -	$ -	$ (3)	$ (3)
Account Problems	$ 496	$ -	$ -	$ 496
Total Questionable Items	$ 4,102	$ 3,453	$ 70	$ 7,625
Adjusted Transition Cost Statement Amount	$ 31,291	$ 30,786	$ 3,451	$ 65,528

The auditors question $7.6 billion, or approximately 10%, of the utilities' total transition cost estimates. As a whole, the audit report has served its purpose of providing the audited net book value for transition cost recovery as of December 31, 1995 and we accept these balances as the starting point for transition cost recovery, recognizing that as proceedings are completed for capital additions for 1996, 1997, and the first three months of 1998, these net book value amounts will be adjusted. We address particular cost categories for starting points as of January 1, 1998 in relevant sections throughout this decision. While the auditors questioned the eligibility of certain cost categories and accepted the eligibility of others, it is up to this Commission to make those determinations. The audit report addressed certain cost categories which will not be considered in this decision, including capital additions, QF contract restructurings and buyouts, employee-related transition costs, and restructuring implementation costs.

The utilities responded to the audit report on April 10, 1997. In general, PG&E, Edison, and SDG&E find the audit findings thorough, accurate, and reasonable. To the extent that costs are questioned because estimates have been used, the utilities explain that it is the actual costs which are relevant. The auditors' findings regarding questioned cost categories are discussed in the pertinent topic area throughout this decision. Edison recommends that, in the future, any similar audits allow for the opportunity for a factual review prior to the issuance of the audit report. We agree that this is a desirable step which should be undertaken to the extent possible, given the time constraints involved in various proceedings.

PG&E requested that a supplemental report be issued regarding its WAPA regulatory assets, QF buyout regulatory asset, and hydroelectric negative net salvage. This request was granted and the supplemental exhibit was filed on June 27, 1997. PG&E filed comments on this supplemental report on July 7, 1997. These audit findings and PG&E's responses are addressed in the relevant sections below.

ORA recommends that a regulatory audit be performed for non-nuclear generation sunk costs being considered for transition cost recovery. We are satisfied with the audit procedures, which were performed in accordance with the directives of the ACR issued on August 1, 1996, and with the scope of the audit as outlined in the auditors' workplan in Exhibit 44. No additional regulatory audit is necessary.

11. Fossil Generation Transition Costs

11.1. Fossil Generation Rate Base and Net Book Value

Each utility has presented an estimate of net book value of its various generation plant assets, as of January 1, 1998. The estimates of net book value or net plant in service include amounts which have been verified as of December 31, 1995 and forecast for January 1, 1998. We are not addressing capital additions in this proceeding; therefore, the final net book value amounts as of January 1, 1998 will be trued-up upon completion of reasonableness review of the capital additions for 1996 and 1997. The majority of these costs are uncontested. Parties generally do not dispute capital investments related to net plant in service, but disagree regarding the treatment of certain rate base items and regulatory assets that must be categorized either as sunk costs or as going forward costs.

11.2. Materials and Supplies Inventory

Each utility has included a request for transition cost recovery related to its investment in materials and supplies inventories associated with the generation function, which PG&E, Edison, and SDG&E categorize as an element of sunk costs. Generally, materials and supplies inventories include stores of materials and supplies, such as spare parts at power plant sites and storage facilities. Materials and supplies inventories are a component of rate base, and the utilities earn the authorized rate of return on their net investment in this inventory. As individual inventory parts are used, they are either expensed or capitalized and depreciated, depending on the particular use and dollar amount involved, and the utility recovers its investment.

The utilities request the following amounts as of January 1, 1998:

PG&E	$13.947 million
Edison	$39.387 million
SDG&E	$10.635 million

11.2.1. The Utilities

PG&E classifies materials inventory by material classes, of which certain classes are specifically related to generation and which PG&E has assigned to fossil power plants. Hydroelectric materials were assigned to watersheds based on inventory location, which were mapped to FERC licenses. In A.96-08-001, PG&E requested transition cost recovery of $14.214 million as of December 31, 1995. In A.96-08-072, PG&E requested transition cost recovery of $13.947 million as of January 1, 1998. As stated in Exhibit 35, the end-of-year 1995 and even the forecast January 1, 1998 materials and supplies inventory balances are not relevant, because the amount that PG&E will seek to recover as transition costs is the above-market costs associated with materials and supplies inventory for a given plant at the time of its market valuation. In other words, PG&E proposes that the market valuation process determine both the level and value of above-market materials and supplies inventory, if any. PG&E states that such above-market costs are uneconomic by definition and therefore eligible for transition cost recovery.

Edison explains that materials and supplies inventories are maintained for operation and maintenance of the company. Included in Edison's request are a combination of materials and supplies inventories that can be specifically identified with non-nuclear generating units and a portion of those inventories not specifically assigned, but supporting all of Edison's functions. Materials and supplies inventories may be stored at individual plant sites or at central locations. Edison requested transition cost recovery of $39.387 million as of December 31, 1995 and has not estimated any change in its request for transition cost recovery as of January 1, 1998.[15]

Edison agrees that any difference between the net book value and market value should be recoverable through the CTC as a generation-related asset. Edison proposes that recovery of the net above-market costs of materials and supplies inventories should be reflected in the market value on the date of divestiture or other market valuation. Edison therefore agrees that recorded amounts as of December 31, 1995 and estimates as of January 1, 1998 are irrelevant for these purposes, as are the audit findings. Edison contends that because shareholders fund the initial investment in materials and supplies inventories, these costs are no different than any other generation-related costs addressed in § 367. Edison emphasizes that once market valuation occurs, replenishment of materials and supplies inventories is a going forward cost, i.e., a component of operation and maintenance costs as addressed in AB 1890.

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[15] Exhibit 115 clarifies that in its February, 1997 update to A.96-08-071, Edison revised its request for transition cost recovery for materials and supplies inventories by approximately $1 million, to $40.349 million. However, excluding 1996 and 1997 capital additions and related items, the January 1, 1998 amount requested is $39.387 million.

SDG&E states that the materials and supplies inventory balances address the cost of materials and supplies currently in inventory, purchased for use in the generation business for construction, operation, and maintenance purposes. SDG&E requests recovery of materials and supplies inventories as recorded on December 31, 1995 of $10.635 million. SDG&E has not changed its request for recovery as of January 1, 1998, and explains that this amount will be updated to reflect the recorded balance as of December 31, 1997. Contrary to PG&E's and Edison's proposals, SDG&E recommends that amortization of the December 31, 1997 recorded book balance of materials and supplies inventories should be completed by way of the 48-month straight line amortization described in D.97-06-060, beginning January 1, 1998. Whether materials and supplies inventories are uneconomic or not should be addressed in the market valuation process, with an appropriate true-up to the transition cost balancing account. SDG&E believes that materials and supplies inventories will be accounted for as part of the market valuation process, but likely not as separate items. In addition, SDG&E believes that the likely market value of these inventories is closer to zero than to the net book value, because each of these components is relatively unique and not readily available. SDG&E does not oppose the auditors' recommendation to use the verified December 31, 1997 balances as a starting point for transition cost recovery and amortization, beginning January 1, 1998.

11.2.2. Audit Report Recommendations

As stated in Exhibits 45, 46, and 47, the auditors found that a qualified opinion was necessary for the requested transition costs as of December 31, 1995, for PG&E, Edison, and SDG&E, because the auditors were necessarily unable to observe the physical inventories of that date. The auditors question the costs as of January 1, 1998 because of the qualification as of December 31, 1995. The auditors were unable to satisfy themselves as to the viability and realizability of these balances through alternative auditing procedures; however, the auditors also state that they are not aware of anything that would cause them to believe that these amounts are materially misstated. The auditors recommend performing additional verification of the materials and supplies inventories balances prior to their acceptance as transition costs eligible for recovery through the CTC. The auditors believe that since § 367 provides for the recovery of generation-related assets that were in rates as of December 20, 1995, the verified uneconomic costs of materials and supplies inventories are eligible for transition cost recovery.

11.2.3. Intervenors

ORA recommends postponing the decision on eligibility of materials and supplies inventories pending divestiture. While ORA is inclined to recommend excluding these inventories from transition cost recovery as going forward costs, it recognizes the possibly uneven treatment inherent in divestiture.

TURN recommends not allowing recovery of materials and supplies inventories not be allowed through the transition cost balancing account. By allowing recovery of the inventory balances as of December 31, 1997 (i.e., ensuring that these amounts are amortized over the transition period, even if trued up for market valuation), TURN believes, the Commission would require ratepayers to pay for assets which are being expensed or capitalized when used and then allow the utilities to replenish these inventories at ratepayer expense with no review. TURN believes that inventory book and market values will be close to identical. Furthermore, TURN contends that decisions to replenish inventories made after January 1, 1998 are going forward costs. If transition cost recovery is allowed, market valuation should be required on January 1, 1998. Any unamortized uneconomic costs should receive the reduced rate of return the Preferred Policy Decision adopted for generation assets eligible for transition cost recovery. Alternatively, TURN proposes that the verified December 31, 1997 unamortized balance should receive the authorized rate of return, with subtractions to that balance as components are used, or as plants are sold with their inventories, with no additions for replenishment or amortization of unused balances.

FEA recommends that materials and supplies inventories are going forward costs and therefore, should not be recoverable as transition costs. To allow such recovery for the January 1, 1998 balances for the investor-owned utilities raises competitive advantage concerns, because competing generators must recover these costs through the market. FEA states that § 367 provides for the recovery of the uneconomic costs of all generation-related assets that were in Commission-approved rates; therefore, materials and supplies inventories represent a cost category that is eligible for transition cost recovery. FEA further states that while the cost category may be eligible for transition cost recovery, it is premature to allow recovery. FEA doubts that sunk inventory costs are uneconomic, since it anticipates that when market valuation occurs, the market value will equal the net book value of these assets. FEA agrees with the auditors' recommendation to exclude that the December 31, 1997 balances from transition cost recovery until they are verified.

FEA also questions Edison's estimates of materials and supplies inventories as of December 31, 1995, asserting that this balance represents a 170% increase from 1994, and recommends that the Commission require Edison to explain and justify this large increase.

CIU recommends that the non-fossil plants' materials and supplies inventory balances be verified and market valued as of December 31, 1997. The uneconomic portions should be recoverable as transition costs. Thereafter, all materials and supplies in inventory that are used must be replenished at each utility's costs and treated as going forward costs, with recovery only from the market.

Because § 367(c) specifically excludes the cost of operating and maintaining the fossil generation units as a going forward cost, EPUC recommends that fossil materials and supplies inventories should not be recovered as transition costs. Because these costs would be the shareholders' responsibility, the proceeds from divestiture or market valuation should also flow to the shareholders. Similarly, EPUC recommends the carrying costs on the unamortized balance of materials and supplies inventory is a going forward cost which must be recovered solely from the market revenues.

11.2.4. Discussion

As of January 1, 1998, the materials and supplies inventories are going forward costs and reflect one component of doing business in the competitive generation market. It is not appropriate to allow the utilities to carry forward existing materials and supplies inventories into the new market, which would confer unnecessary competitive advantages on the utilities and could arguably raise market power concerns. There is no reason that materials and supplies inventories should earn a ratepayer-funded rate of return until market valuation occurs. In D.97-05-088, we determined that there was substantial potential for double recovery for materials and supplies inventories related to Diablo Canyon. Our concerns have not been allayed. As materials and supplies inventories are consumed, such components are either expensed or become part of capital expenditures. We prefer not to establish complicated tracking mechanisms to distinguish between materials and supplies inventories and capital expenditures.

All parties agree that materials and supplies inventories should be accounted for as part of the market valuation process; the question is when that valuation should occur. PG&E agrees that replenishment of materials and supplies inventories after January 1, 1998 is a going forward cost. Edison states that replenishment of materials and supplies after market valuation is a going forward cost. The fact that Edison and PG&E have proposed to divest such inventories along with associated plant is reasonable and fulfills our intent to ensure that the highest possible market valuation can be obtained. To the extent that such components will be divested with the associated plant, the auction price should account for this. In general, we expect that market and book value should be very close, although it may be difficult to distinguish the overall bid into various components.

We will not defer our decision on eligibility as ORA suggests. If divestiture is not completed by December 31, 1997, which we recognize is likely, we find that the materials and supplies inventories should be market valued as of December 31, 1997, or as close to that date as possible, i.e., a physical inventory shall be undertaken with an assessment of the fair market value of the inventory components.

Appraising the materials and supplies inventories as of December 31, 1997, to the extent these components are not yet divested, is reasonable because we expect that market and book value should be reasonably close and that an uneconomic component is unlikely. However, we will allow the difference between market and book costs for materials and supplies inventories to either be debited or credited to the transition cost balancing account. This approach allows market valuation procedures for divestiture and transition cost recovery to be cohesive. It is a far different and simpler undertaking to appraise the market value of various pieces of equipment, than to appraise a power plant. The utilities should report the market value of the materials and supplies inventories in the appraisal applications, due on March 2, 1998, which is subject to scrutiny by parties and this Commission. As of January 1, 1998, materials and supplies inventories for fossil plant assets are going forward costs, which should be excluded from transition cost recovery, consistent with the intent of AB 1890.

Alternatively, the utilities may deem the book value of the December 31, 1997 materials and supplies balances to equal their market value. In this case, the utilities should track the difference between the physical inventories existing as of December 31, 1997 and the physical inventories existing as of the date of actual market valuation. Changes in inventory levels are going forward costs and are not eligible for transition cost recovery.

11.3. Fuel Inventories and Fuel Oil Inventories

Fuel oil inventories are maintained in tanks at each power plant site, as a back-up fuel source in the event that natural gas becomes unavailable. Each of the utilities seeks transition cost treatment of fuel oil inventories, as either sunk costs or as generation-related assets which were being collected in Commission-approved rates as on December 20, 1995. In addition, Edison maintains fuel gas inventories, associated with specific units, as needed for winter reliability, load balancing, and to provide portfolio flexibility. Edison also maintains coal supplies at the Mohave and Four Corners generating stations as active working inventories and emergency on-site inventories to maintain system reliability.

The utilities estimate the following amounts to be eligible for recovery as of January 1, 1998:

PG&E	\$28.9 million: fuel oil inventory
Edison	\$68.8 million: fuel oil inventory
	\$34.7 million: gas inventories
	\$9.6 million: coal inventories
SDG&E	\$13.3 million: fuel oil inventory

11.3.1.The Utilities

PG&E requests \$40.734 million to be recovered as transition costs as of December 31, 1995 and forecasts \$28.493 million to be eligible for recovery as of January 1, 1998. PG&E recommends recovering only the uneconomic portion of the fuel oil inventory balances, as determined at the time of market valuation. PG&E believes its forecast of fuel oil inventories is reasonable, as it has been reviewed by the Commission in D.96-12-080, which adopted a December 31, 1997 forecast of fuel oil inventory. PG&E believes it would be imprudent to burn these inventories down to zero or to sell them for other uses, although PG&E recognizes that it is likely to burn some of its current inventory. Furthermore, PG&E contends that it is the actual balances recorded during the transition period which will be used to determine the amount to be recovered as transition costs. PG&E recommends verifying the actual balances as part of the market valuation process.

Edison requests transition cost recovery related to fuel inventories of \$113 million as of December 31, 1995 and January 1, 1998. Of this amount, \$68.8 million is for fuel oil, \$34.7 million is for gas inventories, and \$9.6 million is for coal inventories. Edison recommends postponing that any decision on the disposition of fuel oil inventory for at least 18 months, to enable the Commission or the ISO to conduct a study on the need for continued back-up fuel oil inventory. In the interim, Edison proposes to retain ownership of the fuel oil inventory and make such inventory available for sale at book value to new plant owners on an as-needed basis. Edison contends that the uneconomic portion of gas and coal inventories should be recoverable through the transition cost balancing account on the date of market valuation. Furthermore, Edison has stated that as of January 1, 1998, carrying costs on fuel inventories are going forward costs and therefore it is not proposing to recover these through transition cost treatment.

SDG&E requests that $13.321 million be found eligible for transition cost recovery related to fuel oil inventories, as of December 31, 1995 and December 31, 1997, and states that this amount will be updated to reflect actual numbers recorded as of December 31, 1997. SDG&E agrees that the economic or uneconomic determination of these assets should be made as part of the market valuation process. Pursuant to the current ratemaking process, SDG&E recommends no amortization of these assets as sunk costs, but rather that the recorded monthly balances earn the 3-month commercial paper rate as carrying costs.

11.3.2. Audit Report Recommendations

Similar to its recommendations for materials and supplies inventories, the auditors have issued a qualified opinion for PG&E, Edison, and SDG&E as of December 31, 1995, because they agree with the estimates in theory, but obviously could not participate in a physical inventory count and assessment of realizability. Again, nothing came to the auditors' attention that would cause them to believe that these estimates are materially misstated. The auditors recommend making a physical count and assessment of realizability be made at year-end 1997 to verify actual amounts. The auditors believe that since § 367 provides for the recovery of generation-related assets that were in rates as of December 20, 1995, the verified uneconomic costs of fuel inventories and fuel oil inventories are eligible for transition cost recovery.

11.3.3. Intervenors

ORA supports PG&E's proposal to determine both the book and market value of its fuel oil inventories at the time of divestiture. ORA also supports SDG&E's proposal to record the carrying charges associated with current inventory levels at the 3-month commercial paper rate until the plant undergoes market valuation, rather than amortizing its fuel oil inventory balances over the 48-month transition period. ORA recommends that unless needed for reliability purposes, which will be confirmed by the ISO, fuel inventory levels should be verified by physical observation at the same time these assets are market valued, and that the difference between market value and book value be included in the transition cost balancing account. ORA has clarified its position that carrying charges will be allowed for 1998 only, which will allow the ISO time to make this assessment.

ORA recommends allowing Edison's requested recovery for gas and coal inventories, based on a market valuation of these inventories as of December 31, 1997, which ORA claims will be relatively simple compared to market valuing power plants, at least for gas inventories. Replenishment of inventory levels after January 1, 1998 would not be eligible for transition cost recovery. ORA declares that deferring market valuation of these inventories until the associated plant is either market valued or sold would allow changes in inventory levels after January 1, 1998 to receive transition cost treatment. ORA contends that for gas inventories, unit prices are available and easily determined on the open market.

While admitting that valuing the coal inventory is more complex, because there is no easily determined market price, ORA disagrees that its market value is zero just because of the difficulty of transporting it to another site. ORA agrees with TURN's overall policy principle that if a plant is economic, none of its components should be found uneconomic on a piecemeal basis. Therefore, only if the coal plants are found uneconomic in comparison with the Power Exchange, and ultimately, upon market valuation, could the coal inventory be found uneconomic. ORA asserts that the value of this inventory will be reflected in its fair market value; i.e., if inventory is larger, the new owner should be willing to pay more since acquisition of the inventory reduces future fuel costs. Thus, the regulatory appraisal proposed by ORA should reflect an arms-length transaction, rather than what might occur if the coal cannot be moved.

TURN states that fuel oil inventory recovery is an exception to its proposal that all costs associated with fuel inventories should be excluded from transition cost eligibility. TURN agrees that, for 1998 only, the decision on recovery of fuel oil inventories should be deferred and that the utilities should be allowed recovery of carrying costs in the transition cost balancing account at the commercial paper rate, pending an ISO decision on the need for fuel oil inventory. TURN further recommends that gas inventories and coal inventories should not be eligible for transition cost recovery, because market and book values should be very close, and because replenishment of inventories after January 1, 1998 is a going forward costs. Alternatively, TURN recommends that if eligibility is allowed, these assets should be market valued on January 1, 1998, subject to a review of prudence, with the commercial paper rate applied to any difference between market and book values which is booked to the transition cost balancing account. This is the current approach under the Energy Cost Adjustment Clause (ECAC).

FEA maintains that fuel inventories should not be allowed transition cost recovery until the Commission is satisfied that the December 31, 1997 balances are reasonable, are uneconomic, are not going forward costs and that allowing recovery of these costs would not confer a competitive advantage on the utilities. In general, FEA asserts that such costs are going forward costs and recovery would therefore violate the standard of competitive neutrality.

CIU recommends excluding fuel and fuel oil inventories from transition cost recovery as of January 1, 1998, because these costs are not part of fossil capital investment, therefore, these costs are going forward costs. In Exhibit 100, CIU's witness Barkovich testifies that the "most important consideration seems to be whether these fuel oil inventories are part of the 'fossil capital investment,' and thus a sunk cost to be recovered or whether they are 'fuel and fuel transportation costs.'" CIU believes that these inventories are related to fuel and fuel transportation costs and are excluded from recovery by § 367(c) as going forward costs. CIU asserts that if § 367(c)(2) is found to apply to Edison's future fuel oil costs, Edison may be allowed to recover such costs.

EPUC states that § 367(c) specifically excludes the cost of fuel and fuel transportation for fossil generation from transition cost eligibility. Therefore, EPUC recommends that fuel inventories are not permitted to be recovered through the transition cost balancing account, nor are carrying costs recoverable. Because fuel inventories are the sole responsibility of the utilities' shareholders, the gain on any sale at divestiture or market valuation should flow to the shareholders. Enron agrees with CIU's and EPUC's assessment of this issue.

11.3.4. Discussion

It is appropriate to defer consideration of the transition cost recovery of fuel oil inventory pending the determination of the ISO as to whether those inventories are needed for system reliability. However, we are not convinced that this is an issue which FERC is considering. Fuel oil inventory issues may remain in this Commission's jurisdiction. The utilities should indicate with specificity the forum in which they expect these issues to be considered and the timing of this consideration. The utilities should include this information in the March 1998 appraisal application. We will defer ruling on the eligibility of transition cost recovery for fuel oil inventories for 1998. The utilities may apply the 3-month commercial paper rate to the unamortized balance of the fuel oil inventory level.

D.94-10-044 adopted a sharing mechanism for Edison's fuel oil pipelines and authorized Edison to enter into third-party contracts to transport fuel oil over its pipeline systems, provided this use did not interfere with the system's back-up capability. (56 CPUC2D, 642, 648.) This sharing mechanism allocated 87.5% of gross revenues to shareholders and 12.5% to ratepayers. We do not have the record to determine how this sharing mechanism interacts with the fuel oil inventory levels maintained by Edison. We direct Edison to file a proposal for the treatment of fuel oil inventory which is consistent with the guidelines established on this decision and which ensures that ratepayers continue to benefit from the gross revenue mechanism. Edison shall include this proposal in its appraisal application, to be filed on March 2, 1998.

For gas and coal inventories, it is reasonable to market value these components as of December 31, 1997 or as close to that date as possible. To the extent that divestiture occurs prior to year-end 1997, we will have that information. Again, we wish to establish a bright line for determining uneconomic costs up to January 1, 1998 and going forward costs after that date. Deferring market valuation of these inventories until the associated plant is either market valued or sold would allow changes in inventory levels after January 1, 1998 to receive transition cost treatment.

If divestiture is not complete, and for those assets retained by the utility, it will be relatively simple to compare the market price of gas with the book value of Edison's gas inventory. While coal may be more difficult, the value of the coal inventory is not based on transporting it to a different power plant, but on its intrinsic market value. Once the applications initiating market valuation by appraisal are filed, we will direct the Energy Division to hold a technical workshop devoted to these very specific appraisal issues for coal in advance of the generic issues of market valuing plants retained by the utilities. In this way, we can establish a bright line between inventory costs eligible for transition cost recovery and those that will be classified as going forward costs as of January 1, 1998. Replenishment of inventory levels after January 1, 1998 will not be eligible for transition cost recovery. Carrying costs should not be allowed on any unamortized difference between market and book value. Because the transition cost balancing account itself will be subject to the commercial paper rate of interest, there is no need to apply an additional interest rate calculation. In the alternative, Edison may deem the book value of the December 31, 1997 gas and coal inventories balances to equal their market value. In this case, Edison should track the difference between the physical inventories existing as of December 31, 1997 and the physical inventories existing as of the date of actual market valuation. Changes in inventory levels are going forward costs and are not eligible for transition cost recovery.

11.4. Non-nuclear Decommissioning

Non-nuclear decommissioning refers to the obligation to remove a major utility facility, usually a power plant. Under traditional cost-of service regulation, it is the utility's obligation to remove retired plant and to mitigate environmental and other effects associated with that retired plant. Decommissioning costs are estimated as a specific dollar amount of the costs involved in dismantling the facility and are amortized through the annual depreciation accrual. In other words, non-nuclear decommissioning costs are a component of each utility's depreciation expense, based on each utility's most recent general rate case (GRC). PG&E, Edison, and SDG&E contend that since generation facilities were constructed to serve ratepayers, who would then receive the benefits of these facilities over their useful lives, these costs should be recoverable as eligible transition costs. The intervenors do not dispute the eligibility of this category, but question how the costs are calculated and what amount, if any, should be included in the transition cost balancing account for amortization beginning January 1, 1998, as opposed to the amount that should be determined through market valuation.

The utilities estimate the following amounts as of January 1, 1998:

> PG&E: $596.168 million (net nominal amount, to 1/1/98 to determine that amount amortized through transition cost balancing account)
>
> Edison: $365.266 million
>
> SDG&E: $ 70.749 million

PG&E has no estimates of decommissioning costs for its hydroelectric facilities, but estimates negative net salvage amounts for these facilities of $273.6 million.

11.4.1. Utilities

PG&E believes it will retain the environmental liability for generating plant, whether plant is divested, retained, or retired, and that this liability should be recovered as an eligible transition cost. As of January 1, 1998, PG&E proposes to begin to recover decommissioning cost estimates based on its most recent GRC-authorized amounts. At the time of market valuation or retirement, PG&E recommends truing-up the transition cost balancing account to reflect any revised amounts.

PG&E also anticipates that it will retain the non-environmental liability for retired plant, which it proposes to recover through the transition cost balancing account, but predicts that it is likely that the non-environmental decommissioning obligation will be transferred to the buyer upon divestiture of the plant. If plant is retained by the utility, PG&E expects that the appraisal value would consider and reflect these costs. As of January 1, 1998, PG&E proposes to begin to recover decommissioning cost estimates based on the amounts authorized in its most recent GRC. As the time of market valuation or retirement, PG&E proposes to true-up the transition cost balancing account to reflect any revised amounts.

Edison thinks that non-nuclear decommissioning, including any environmental requirements, should be the responsibility of the owner of the generating station. The estimated costs should be determined at the time of market valuation, whether by appraisal or divestiture. Edison maintains that this position is supported by ORA, TURN, and CIU. Edison agrees with ORA's proposal to continue to recover decommissioning costs at the level currently included in authorized rates.

Assuming that decommissioning costs will be determined through the market valuation process, Edison proposes to continue the accounting for accumulated decommissioning amortization as an offset to rate base. This is in contrast to PG&E's proposal to remove the decommissioning reserve from rate base, which Edison asserts would require determining the present value of the pre-2001 obligations and applying interest calculations on the unpaid decommissioning funds.

Edison contends that because D.97-08-056 precludes the utilities from recovering the costs of environmental remediation at its fossil sites through the Hazardous Waste Mechanism, Edison must seek recovery of these costs through either the Environmental Compliance regulatory asset or through environmental decommissioning. Edison explains that environmental remediation generally cannot be performed until final decommissioning, so it agrees with PG&E that it is necessary to estimate this obligation. Edison agrees with ORA's recommendation to base these costs on actual work performed for divested plants and on costs estimated through soil studies for plants not divested, with the caveat that such work must occur prior to 2001. Otherwise, Edison claims that all environmental remediation costs would need to be based on soil studies, rather than actual costs, and included in the four-year transition period.

SDG&E recommends amortizing the forecasted decommissioning expense (for both environmental and non-environmental decommissioning) ratably over the transition period. The economic or uneconomic treatment should be determined in the market valuation process, with the transition cost balancing account trued-up appropriately. SDG&E states that the ORA and TURN proposal to continue the current depreciation expense levels to include decommissioning until market valuation occurs and to allow CTC recovery for environmental costs is an acceptable alternative.

11.4.2. Audit Report Recommendations

The auditors explain that PG&E was authorized to collect fossil decommissioning costs in its 1996 GRC decision (D.95-12-055). The company was allowed to collect decommissioning funds based on estimated decommissioning costs, with the expectation that actual costs would be trued-up with collections at the time of actual decommissioning. The auditors questioned PG&E's estimates of decommissioning costs, because PG&E escalated the estimate for each plant to nominal (or current) dollars as of the expected date of decommissioning or 2001, whichever is sooner, using the same Consumer Price Index (CPI) inflator factors used to escalate decommissioning costs to the 1996 test year in the 1996 GRC. This escalated cost was then discounted to January 1, 1998 net present value amounts using a discount rate of 7.17% (the reduced return on transition cost assets for PG&E, as discussed in Section 18). In D.95-12-055, we specifically denied PG&E's request to base decommissioning costs on nominal dollars and instead required that costs be based on constant 1996 dollars. The auditors believe that the net present value calculation is acceptable for these purposes. The auditors also recommend reviewing contingencies and labor overheads, since there may not be a true-up to actual costs in the transtion cost recovery process for plants that are decommissioned after the transition period.

Negative net salvage results when the cost of removing a facility exceeds the amount that is expected to be received from the sale or other disposition of the retired unit. Salvage and removal costs reflect actual amounts recorded at the time of the retirement, and retirement costs reflect original cost. Depreciation reserves are trued-up for revised net salvage estimates and adjusted for revised remaining lives based on updated depreciation studies. PG&E relied on published depreciation statistics for other utilities to determine net salvage percentages with respect to retirement of its hydroelectric facilities, because it did not have sufficient data to develop its own statistics. The auditors determined that these amounts were estimated correctly and that the negative net salvage amount is appropriate to include in PG&E's estimate of transition costs. The auditors note that because net salvage factors are embedded in depreciation rates, it is difficult to identify the amount of net salvage included in the reserve for depreciation at any one time. The auditors explain that this is not necessary because the proper approach is to assume that classes of plant assets will be fully depreciated before salvage factors produce additional accruals. The auditors recommend recovering this cost through market valuation rather than as a charge to the transition cost balancing account. PG&E agrees with this recommendation and states that this cost category will not be recovered as a separate item in the transition cost balancing account, but will be factored into the market valuation of PG&E's hydroelectric facilities as part of the depreciation reserve. FEA agrees and recommends that we carefully review these amounts.

The auditors explain that Edison recovers fossil decommissioning costs in its depreciation rates and the collected decommissioning costs are included in the depreciation reserve balance (which is an offset to rate base). The auditors have not questioned decommissioning costs for Edison, because Edison explains that the future owners of these plants will assume the decommissioning obligation. Edison explains that any amounts collected through depreciation or future net salvage will be deducted from the unamortized investment upon market valuation. The auditors have not questioned any of SDG&E's decommissioning costs.

11.4.3. Intervenors

On a policy level, ORA asserts that decommissioning expenses for fossil plants do not create the same kind of public safety concerns posed by nuclear decommissioning, which costs are to be recovered through a separate nonbypassable rate. ORA contends that non-nuclear decommissioning is not a past investment by shareholders, but a future obligation of the utilities. ORA recommends that non-nuclear decommissioning costs should not be estimated at this time. ORA agrees that environmental decommissioning costs should be directly recoverable through the transition cost balancing account, based on actual work performed for divested plants and based on soil studies for plants which are not divested. For non-environmental decommissioning, ORA recommends that for divested assets or assets retained but not retired during the transition period, any unfunded non-environmental decommissioning costs at the time of market valuation should be reflected through the market price of the asset.

Prior to market valuation, amortization of the non-environmental decommissioning costs should be permitted at the most recent GRC-authorized level over the 48-month amortization period, on a straight-line basis, according to ORA. Upon market valuation, future decommissioning obligations would be transferred either to the new owners or to shareholders, and further transition cost recovery for these costs would cease. This approach reflects ORA's preference for market mechanisms and eliminates the need for separate accounting for decommissioning costs. In addition, ORA maintains that separate recovery of unfunded decommissioning expenses through the transition cost balancing account would be anticompetitive. Non-environmental decommissioning costs of assets retired during the transition period should be recoverable through the transition cost balancing account.

TURN agrees that the utility retains the environmental liability whether the plant is divested, retained, or retired and should recover this cost through the transition cost balancing account. The timing of environmental decommissioning should be accounted for in a net present value calculation to the extent it occurs after 2002. TURN also recommends that the utility should retain the non-environmental decommissioning obligation of retired plants.

TURN believes that the non-environmental decommissioning obligation should transfer to the buyer if the plant is sold. If the plant is retained, the appraisal price will account for and reflect these costs. Again, TURN recommends that the appraisal take into account the timing of decommissioning after 2001 through a net present value calculation.

For both environmental and non-environmental decommissioning, to the extent any decommissioning costs are recovered prior to being spent, these costs should be accounted for as a rate base offset. As of January 1, 1998, TURN recommends that the most recent GRC-authorized amounts should be included as a current transition cost (i.e., amortized over the 48-month transition period). These costs should then be trued-up as plants are divested and decommissioning obligations become clearer.

FEA has not distinguished between environmental and non-environmental non-nuclear decommissioning. FEA recommends that decommissioning should be stated in present value amounts, not nominal dollar amounts, and is concerned that contingency funds may be collected for contingencies which will not arise. FEA agrees with the auditors that PG&E's negative net salvage for hydroelectric facilities should not be eligible for transition cost recovery, but rather should be reflected in the market valuation process.

CIU agrees with Edison's proposal and finds it preferable and more accurate to use the market mechanism of divestiture or other market valuation to transfer this responsibility either to a new owner or to utility shareholders through the appraisal process. The amount of decommissioning to be recovered should be determined in conjunction with the market valuation of all non-nuclear generation. CIU recommends that estimates should be avoided if possible and that contingencies should be excluded.

EPUC agrees with Edison's proposal to include both the environmental and non-environmental decommissioning obligation in the transition cost balancing account through the market valuation of the generating plants, which shifts the responsibility for decommissioning to the future owner. EPUC recommends that accumulated decommissioning amortization should continue as an offset to rate base.

11.4.4. Discussion

It is important to distinguish between the recovery of generation-related environmental decommissioning costs and costs recovered in the Hazardous Substance Mechanism (HSM). The HSM recovers costs that are not already recovered in rates, whereas environmental decommissioning is recovered in current rates through the decommissioning expense. (RT: 918, 2974.) D.97-08-056 prohibits the utilities from entering any costs associated with generation into their HSM accounts. (D.97-08-056, mimeo. at 10.)

We are persuaded by PG&E's argument that, in accordance with state and federal law, the utilities remain liable for contamination on power plant property. Because it is not probable that the environmental decommissioning responsibility can be transferred to new owners, we will allow the uncovered portion of the costs in rates to be amortized as a current cost in the transition cost balancing account. Amortization of these costs are eligible for acceleration. We will treat these costs as a current rate base offset, as they are accumulated prior to being spent. The timing of environmental decommissioning costs after 2001 should be accounted for in a net present value calculation.

To the extent that the environmental non-nuclear decommissioning can be transferred to new owners and is reflected in the purchase price, we will require appropriate true-ups and credits to the transition cost balancing account. In addition, the utilities are required to true-up the transition cost balancing account according to updated studies and actual costs incurred. Assuming plants are retired before the end of the transition period, a study should be completed of the costs of decommissioning and appropriate true-ups should be made to the transition cost balancing account for costs of actual decommissioning work (both environmental and nonenvironmental) and revised decommissioning studies. A review of this methodology will occur in the annual transition cost proceeding.

Consistent with our preference to use market mechanisms when possible, we concur that the market valuation process for both divested and retained plants will yield more accurate and useful values of non-nuclear non-environmental decommissioning costs than will an estimate of what these expenditures are likely to be. We will adopt Edison's recommendation that non-nuclear non-environmental decommissioning should be the responsibility of the owner of the generating station. We will not estimate these costs now, but will determine them at the time of market valuation, whether by appraisal or divestiture.

Both environmental and non-environmental non-nuclear decommissioning costs should continue to be recovered at the level currently included in authorized rates and amortized beginning January 1, 1998. As both Edison and TURN recommend, the accumulated decommissioning amortization should be accounted for as an offset to rate base. There is no need for accelerated depreciation of the non-nuclear decommissioning expense, because the non-environmental amounts will be reflected in the market valuation process. We agree with ORA that any unfunded amounts are going forward costs and as such, should not be included in the transition cost balancing account. Accelerating the depreciation of these costs would merely blur this bright-line test.

We cannot predict when these costs will be incurred, but we are convinced that it does not make sense to treat all of these costs as if they will be incurred by 2001. We will allow recovery of non-nuclear decommissioning costs in the transition cost balancing account to the extent they are allowed in current rates. This is a reasonable approach which allows some of these costs to be collected prior to market valuation, but will then adjust for market valuation. As we have previously declared, it is important that market valuation occur sooner rather than later. Divestiture is proceeding; we are initiating appraisal of retained assets in early 1998. There should certainly be additional information available to make these adjustments well before 2001. Costs recovered in rates should continue to be treated as a rate base offset.

We concur with the approach to hydroelectric negative net salvage recommended by the auditors and agreed to by PG&E: the $273.6 million estimated in this cost category will not be recovered as a separate item in the transition cost balancing account, but will be factored into the market valuation of PG&E's hydroelectric facilities as part of the depreciation reserve.

11.5. Construction Work In Progress and Retirement Work In Progress

The Construction Work In Progress (CWIP) account includes costs for projects that were under construction as of December 31, 1995. Under traditional ratemaking, CWIP costs are either charged to future plant additions or to abandoned plant accounts. Future plant additions will be evaluated for reasonableness in the appropriate capital additions proceeding using the requirements delineated in § 367 and specified in D.97-09-048. CWIP costs include, for example, costs for plant additions, major equipment modifications, hydroelectric plant relicensing, and replacement of equipment. For purposes of market valuation, PG&E and Edison recommend that CWIP be considered a sunk cost which will be reflected in the net book value of the plant at the time of divestiture or other market valuation. The utilities also presented CWIP balances for 1996 and 1997, which represent projects for which construction is not yet complete and costs are not yet transferred to plant in service. These balances will be addressed in the appropriate capital additions proceeding. Parties generally agree that CWIP balances should be recovered as capital additions when the projects are transferred to plant in service and not separately.

Retirement Work in Progress (RWIP) are the costs involved with retirement of plant assets, such as the cost of removal and salvage. While CWIP is not part of rate base, RWIP is accounted for as part of the accumulated depreciation reserve; i.e., accumulated depreciation reserve is an offset to rate base and RWIP decreases that reserve. Edison recommends that RWIP should not be excluded from transition cost recovery, because RWIP is not associated with CWIP, nor will these costs be dealt with in the capital additions proceeding.

11.5.1. Utilities

PG&E presented a balance of $35.3 million in CWIP as of December 31, 1995. In general, PG&E recommends recovering CWIP balances in capital additions when those projects are transferred to plant in service. However, PG&E recommends recovering CWIP balances for projects started prior to December 31, 1995 in the transition cost balancing account, if the corresponding capital additions are not approved. PG&E contends that costs that are not eligible for capital addition treatment, but were incurred prior to the effective date of AB 1890 and were approved in the GRC should be eligible for transition cost recovery as abandoned projects. PG&E also recommends that CWIP be considered a sunk cost in the market valuation process; e.g., for divested plants, CWIP would be transferred to the new owners and reflected in the net book value of that plant. The audit report did not question costs related to the December 31, 1995 balance, but did question certain costs included as CWIP as of January 1, 1998.

Edison has a balance of $74.3 million in CWIP as of December 31, 1995. Edison states that CWIP recovery has not been proposed in this proceeding, with the understanding that CWIP assets identified on December 20, 1995 which close to capital additions between 1996 and 2001 will be reviewed and recovered as capital additions in future years. However, Edison states that any CWIP existing as of December 31, 1995 should be eligible for recovery through the transition cost balancing account, if it is not recovered as a capital addition. Edison agrees that CWIP should be included in the market valuation process, i.e., to the extent there is any CWIP remaining on the date a generation plant is sold to a new owner, it should be reflected in both the book and market values of that station. Edison recommends including RWIP as part of the depreciation reserve and states that ORA now agrees with this treatment. The audit report questions two projects which the auditors believe were improperly included in Edison's CWIP balance as of December 31, 1995, the total of which is $3.5 million.

SDG&E presents a CWIP balance of $20.2 million as of December 31, 1995 and a RWIP balance of $290,000. SDG&E recommends considering CWIP issues in the capital additions proceeding; however, CWIP amounts booked prior to December 20, 1995 should be viewed differently. SDG&E notes that some CWIP will become abandoned plant and will be addressed in the capital additions proceeding. SDG&E maintains that it is premature to adopt TURN's recommendation to exclude CWIP from transition cost recovery.

The audit report notes that SDG&E ceased construction and reversed charges totaling $143,000 which SDG&E expects will not be eligible for transition cost treatment under the requirements of AB 1890. The auditors concur with this treatment.

11.5.2. Intervenors

ORA recommends that CWIP balances should only receive transition cost treatment when the related capital addition is approved and moved to a plant account. ORA shares TURN's concerns regarding the potential for double recovery. If the related capital addition is not approved, the associated CWIP should not be recoverable through the transition cost balancing account. However, ORA also recommends that specific projects which were reasonable when initiated, but which do not meet the criteria established in AB 1890, should be reviewed in the appropriate capital additions proceeding. ORA explains that the Commission rarely approves specific projects in GRC decisions, but approves only a forecasted rate base. ORA agrees that abandoned plant treatment for these projects may be appropriate, but, again, suggests that this be determined in the capital additions proceedings. ORA no longer questions transition cost treatment for RWIP accounts for Edison.

TURN recommends that CWIP be ineligible for transition cost recovery, because of the potential for double counting. TURN recommends recovering that CWIP balances in capital additions when projects are transferred to plant in service. If CWIP balances are not deemed eligible for transition cost recovery through capital additions, these balances should be addressed on a case-by-case basis. TURN advocates that CWIP investments imprudently incurred should not be recovered at all and that expenditures incurred in 1996 and 1997 are of particular concern, given that such investments may have been undertaken to enhance the utilities' competitive positions while continuing to be assured of transition cost recovery. TURN recommends that rather than the effective date of AB 1890 or December 31, 1995 being earmarked as the milestone for decision-making regarding capital investments,the issuance of Rulemaking (R.) 94-04-031/Investigation (I.) 94-04-032 on April 20, 1994 is more appropriate.

FEA recommends addressing CWIP in the capital additions proceeding and contends that the audited CWIP balances as of December 31, 1995 are the appropriate balances to be reflected in CWIP accounts until 1996 and 1997 plant additions are approved.

EPUC recommends recovering CWIP in capital additions when the projects are transferred to plant in service, provided the capital additions have been determined to be eligible pursuant to AB 1890, including those costs incurred prior to December 31, 1995. EPUC states that cost recovery for RWIP is currently reflected in depreciation and amortization accounts in rates approved by the Commission and that these costs should be treated similarly to non-environmental decommissioning costs.

11.5.3. Discussion

If CWIP costs are not allowed in the capital additions proceedings, the utilities, in effect, are requesting to recover these costs as abandoned projects. Parties have briefed the traditional ratemaking approach to abandoned plant. Under cost-of-service ratemaking, the utilities request recovery for abandoned projects in the GRC immediately following abandonment. If recovery is authorized, the utility is allowed to amortize the recorded costs in CWIP, less any accrued Allowance for Funds Used During Construction (AFUDC) over a specified number of years, without any interest. The criteria for abandoned project recovery are delineated in D.83-12-068, as modified by D.84-05-100 and D.89-12-057, and include the following: 1) the project was initiated and completed during a period of unusual uncertainty and dramatic and unanticipated change; 2) the project was found reasonable, both in terms of undertaking and proceeding with the project; and 3) projects were canceled promptly when conditions warranted:

> "The general rule of ratemaking has been that a utility is not allowed to recover the costs of a plant which is not used or useful. But we have created an exception during periods of great uncertainty: 'The exception is the product of the period of dramatic and unanticipated change, initiated most notably for utility planners by the oil embargo of 1973, and extending for almost a decade. The period was characterized

> by great uncertainty in the energy industry, both as to demand growth and availability of supply....During such a period, the ratepayer should participate in the increased risk confronting the utility.
>
> "'But the ratepayer does not become the utility's underwriter in a period of high risk. At all times, the shareholder will bear some of the risks of abandoned projects. The utility should bear a major part of the risk in order to provide proper, management incentives. Also, the ratepayer's participation is limited to those abandoned projects...for which the utility demonstrates to us that it has exercised reasonable managerial skill. We emphasize that the utility bears the burden of proof of reasonableness, not only with respect to the planning and conduct of a given project, but also regarding the cancellation, which must have occurred promptly when conditions warranted. Finally, a perception merely of generalized and ill-defined risk will not suffice to invoke this exception to the 'used and useful' principles. The utility will have to demonstrate that the project which it ultimately abandoned was reasonable throughout the project's duration in light both of the relevant uncertainties that then existed and of the alternatives for meeting the service needs of its customers....' ([quoting from] D.84-05-100, mimeo. pp.3-4)." (D.89-12-057, 34 CPUC 2d 268-269.)

According to PG&E, abandoned project treatment has been typically extended to projects that were no longer economic or necessary. PG&E contends that while these particular projects are economic and necessary, they may not be recoverable due to criteria yet to be identified by the Commission. Further, PG&E contends that restructuring is a period of protracted uncertainty and that because these projects were approved in PG&E's GRC, it would have been imprudent not to continue those projects necessary to maintain generation-related plants. Furthermore, PG&E states that all of these projects were commenced and many were completed before the enactment of AB 1890 and that several were so close to being complete as of December 31, 1995, it would have not been wise to cancel them. PG&E explains that abandoned projects are often canceled in the early phases before physical construction begins.

We do not believe that there was such uncertainty in the electric utility industry due to restructuring as to relieve the utilities of the risk of recovering CWIP costs incurred prior to 1995 which are not found eligible for transition cost recovery in the capital additions proceeding. Indeed, we are concerned that ensuring transition cost recovery for such items could not only lead to double counting, but could confer significant competitive advantages on the incumbents. Therefore, we will exclude transition cost recovery for CWIP for now. Those projects approved in the relevant capital additions proceedings will receive transition cost recovery, because the net book value and associated depreciation amounts are trued-up as a result of those proceedings. Those costs incurred prior to December 31, 1995 which are not approved in the capital additions proceedings do not meet our established criteria for abandoned plant and therefore are not approved for transition cost recovery. To the extent that there is remaining CWIP on the date a generation station is sold, that amount should be reflected in both the book and market values of that station. We will adopt a different treatment for past hydroelectric relicensing costs, as explained in Section 14.

Edison explains that the FERC Uniform System of Accounts requires that when depreciable electric utility plant is retired, the book cost of the retired plant be entered into Account 108, the Accumulated Provision for Depreciation. While the retirement work is in progress, the removal and salvage costs are accounted for in work orders that are also entered into Account 108. If plant is retired before the end of its estimated useful life, traditional ratemaking has provided that shareholders are able to recover their remaining investment in the plant, but not earn any return on the remaining undepreciated plant balance. (D.85-08-046, 18 CPUC 2d 592.) Edison believes that under restructuring, this approach to accounting and ratemaking should not change significantly. As plants are retired with appropriate adjustments to the depreciation reserve and capital additions are added to rate base, the uneconomic portion of the net generation plant will be subject to transition cost recovery.

PG&E adds that under traditional ratemaking for utility plant, assets are depreciated using group depreciation at the asset class or FERC plant account level. Under this approach, assets are depreciated based on average life and when a plant is retired, it is considered to be fully depreciated; i.e. its original cost amount is removed from plant in service and from the accumulated depreciation reserve, with no net change in total book value. Any undepreciated value associated with the asset on retirement is spread to all other assets in a given class or account. PG&E agrees that any remaining net book value will be amortized through the transition cost balancing account over the remaining months of the transition period. For plants that have been retired prior to the beginning of the transition period, there is no impact on transition cost recovery, other than decommissioning funds.

ORA does not propose any changes to traditional ratemaking for retired plant for purposes of transition cost recovery. After market valuation, ORA recommends that ratepayers should no longer be responsible for any additional costs associated with retiring a power plant, including decommissioning.

We agree that RWIP costs should continue to be accounted for as an increase to the accumulated depreciation reserve. As discussed under decommissioning, after market valuation, ratepayers should no longer be responsible for any additional costs associated with retiring a power plant, including decommissioning.

11.6. Common and General Plant

Common plant is defined in the FERC Uniform System of Accounts as those assets associated with more than one utility service, such as electric, gas, and water. (TR: 2454; 18 CFR, Part 101, p. 280, April 1, 1996.) General plant is not defined in the FERC Uniform System of Accounts, but the following accounts are described under the heading of "General Plant:" land and land rights, structures and improvements, office furniture and equipment, transportation equipment, stores equipment, tools, shop and garage equipment, laboratory equipment, power operated equipment, communication equipment, miscellaneous equipment, and other tangible property. Each of these accounts is then characterized as including items not properly included in more specific accounts, in conformance with FERC instructions. (*Ibid*, Accounts 389-399, pp. 329 - 331.) The issue in this proceeding is how to define and treat generation-related common and general plant for PG&E and SDG&E, and general plant for Edison.[11] A certain amount of common and general plant has been allocated to the generation function for each utility in the cost separation proceeding (A.96-12-009 *et al.*) The utilities assert that generation-related common and general plant costs are eligible for transition cost recovery, because they are generation-related costs that were in Commission-approved rates on December 20, 1995 and claim the following estimates as of January 1, 1998:

PG&E:	$80.050 million
Edison:	$42.929 million
SDG&E:	$4.388 million

11.6.1. Utilities

PG&E proposes to recover the uneconomic portion of common and general plant, which the Commission has determined to be generation-related, in the transition cost balancing account, whether such plant is on-site or off-site. PG&E states that it has included only costs associated with common and general plant that had been directly assigned to generation in its accounting records and that this plant is associated with land, buildings, communications, and other equipment located at the generation plants that are immobile and essential to the generation function. PG&E believes this on-site plant should be market valued with the generating plant.

PG&E has not allocated any shared common plant costs, such as those associated with its general office, to generation in this proceeding. PG&E proposes that the amount of shared common plant ultimately determined to be generation-related in the unbundling proceeding should be assigned to generation and therefore be eligible for transition cost recovery, if found to be uneconomic. PG&E asserts that these costs are generation-related that are unavoidable until PG&E's generation has been completely divested. PG&E recommends that off-site assets which

[11] Because Edison is an electric utility only (other than the small gas and water operations it maintains on Santa Catalina Island), there is no common plant at issue.

are determined to be generation-related in the unbundling proceeding should also be market valued, but this issue should be considered in another phase of this proceeding.

PG&E contends that ORA's position in this proceeding is inconsistent with its position in the unbundling proceeding. In that proceeding, ORA has agreed that both the directly-assigned and indirect allocated costs assigned to generation are appropriate, and furthermore, ORA argued that additional shared common costs should be allocated to generation.

Edison asserts that all generation-related general plant should be eligible for recovery in the transition cost balancing account, which will then be adjusted for market valuation. Edison has no common plant, but provides an analysis of two types of generation-related general plant: 1) site-specific, i.e., which is situated at the generating site and 2) non-site-specific, i.e., assets which are not necessarily physically located at the generating site. Edison contends that both types of assets represent plant invested in specifically to serve the generation function. Edison believes that if the Commission allows recovery only of site-specific general plant in the transition cost balancing account, the remainder of non-site-specific plant should be recovered in non-generation rates. Edison states that site-specific general plant assets were purchased and have been used solely for the operation of generating plant and do not have other uses within the utility; these assets have been included in its divestiture proposals.

Edison disputes ORA's proposal to defer resolving the eligibility of on-site general plant assets until it can be determined which assets will be divested. Edison believes that this violates the Preferred Policy Decision, which orders recovery of up to 100% of the net book value of fossil generation prior to market valuation. Edison further disputes ORA's and TURN's recommendations that no transition cost recovery be allowed for off-site generation-related general plant assets which are either allocated or directly assigned to generation and involve activities that could be reassigned to other utility functions.

SDG&E states that all of its common and general generation-related plant assets are site-specific and should be recovered as generation-related transition costs. SDG&E recommends that the booked amounts should be amortized over the 48-month transition period and that the determination of which portion is uneconomic or economic should be reflected in the market valuation process.

11.6.2. Intervenors

ORA asserts that we must determine whether these assets are directly related to generation, whether the cost is unavoidable, and whether the cost is uneconomic. ORA states that on-site plant which is immobile and essential to the generation function is more directly related to generation than is off-site plant, and that items which are directly assigned to generation are dedicated to the generation function, while items which are indirectly assigned though various allocation methods serve multiple functions. ORA believes that common and general plant assets vary in the degree to which they are unavoidable and recommends that the cost of assets which can be sold, leased, or reassigned to other utility functions is avoidable and therefore not eligible for transition cost recovery. ORA recommends that determining the eligibility of on-site common and general plant should be postponed pending divestiture of the related plants. ORA believes that the off-site common and general plant should not be eligible for transition cost recovery, because the related assets have alternative uses and would be very difficult to market value. Alternatively, ORA recommends that if off-site common and general plant is allowed to be recovered, it should be eligible for inclusion in the transition cost balancing account only if its market value exceeds its book value.

TURN agrees that the uneconomic portion of the on-site common and general plant should be recoverable in the transition cost balancing account and that the on-site assets should be market valued with the related plant generating plant. TURN argues that the off-site common and general plant should not be eligible for transition cost recovery, because these costs are likely to have other uses and are therefore not stranded. TURN recommends that common and general plant which is directly assigned to generation and shared plant which is allocated to generation be deemed ineligible for transition cost recovery. In particular, TURN recommends that shared corporate general plant should not be eligible for transition cost recovery, because these assets are very likely to have alternative uses. TURN also asserts that including off-site common and general plant as eligible for recovery creates perverse incentives influencing the choice between owning and leasing property.

FEA recommends that, unless the utilities can demonstrate that these assets cannot be transferred to other operations or sold at a price equal to or above net book value, these costs should be ineligible for transition cost recovery. FEA asserts that assets, such as vehicles or land, whether on-site or off-site, that may have been used in generation functions in the past may well be usable in the utility's other operations. FEA questions whether such assets are indeed generation-related. FEA contends that divestiture will aid us in our determination of whether an asset claimed by the utility as eligible for transition cost recovery is truly generation-related or not. FEA thus agrees with ORA's proposal that recovery of these assets be deferred until market valuation.

EPUC agrees that the uneconomic portion of the on-site common and general plant should be determined through market valuation and that the uneconomic portion should be eligible for transition cost recovery to the extent it is included in the net book value of capital investment existing as of January 1, 1998. EPUC recommends deferring the market valuation and treatment of off-site common and general plant to Phase 3 or other Commission proceeding, and states that the treatment of these items depends on the proper assignment or allocation of the off-site facilities to various generation plants; e.g., properly allocated off-site common and general plant costs that were part of the net book value may receive transition cost recovery. However, EPUC recommends that if such costs are not part of the net book value, then the costs should be recovered from the Power Exchange or the market.

11.6.3. Discussion

We will distinguish between on-site and off-site common and general plant in our discussion. On-site common and general plant are generation-related assets which appear to be integral to the operation of the corresponding power plants. It would be inconsistent with our efforts to encourage divestiture and to maximize the fair market value of these assets to either not allow recovery of any transition costs associated with these assets or to defer the determination of their eligibility for transition cost recovery. We will allow transition cost recovery via amortization of the on-site common and general plant estimates at the beginning of the transition period and it is our expectation that market valuation will capture the value of such assets. In order to be consistent in our ratemaking approach, the amount of on-site common and general plant assets as of December 31, 1995, which has been verified by the auditors, should be amortized over the transition period. We will true-up the transition cost balancing account once market valuation occurs and will review any assets not acquired by buyers to determine whether they remain eligible for transition cost treatment.

Off-site generation-related common and general plant is more problematic. We will exclude such costs from transition cost recovery at this time, because we expect that the majority of items in this category may well be usable in other unregulated areas of the utilities' or their affiliates or subsidiaries' functions.[30] We agree with ORA that such assets should have many uses; indeed, PG&E has indicated that of its 20,000 accounting records, 19,000 relate to vehicles and another 25 relate to buildings. We believe that there are many opportunities to minimize transition costs in the area of off-site common and general plant. We adopt PG&E's proposal that off-site generation-related common and general plant not be recovered initially in the transition cost balancing account pending efforts by the utilities to mitigate such costs.

To the extent these off-site common and general plant costs cannot be fully mitigated, the uneconomic costs of off-site generation-related common and general plant may be recoverable through transition cost treatment. However, we put the utilities on notice that such mitigation efforts will be thoroughly reviewed and

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[30] Such transactions must be undertaken in conformance with our affiliate transaction rules being developed in the affiliate transaction rulemaking, R.97-04-011/I.97-04-012.

scrutinized in the annual transition cost proceedings and that we expect the utilities to use their best efforts to find alternative uses for these assets.

11.7. Emissions Trading Credits

Emission trading credits are used by the utilities to offset certain air pollution emissions under a program established by federal statute. Excess emission trading credits not needed by the utilities can be bought and sold in a secondary market. We have generally found that 100% of the total net value of these credits (less only the sales costs) should be returned to ratepayers. These policies were adopted in D.95-12-051 (for PG&E) and in D.95-04-076 (for SDG&E). Both PG&E and SDG&E are subject to the Environmental Protection Agency's sulfur dioxide (SO2) emissions program. Edison's fossil-fired plants are subject to the South Coast Air Quality Management District's nitrogen oxide (NOx) emissions program through its Regional Clean Air Incentives Market (RECLAIM).

In terms of ratemaking, we have used the ECAC for PG&E and SDG&E to ensure that ratepayers receive this credit. Edison uses its Electric Revenue Adjustment Mechanism (ERAM) account for this purpose and has proposed to continue doing so in A.95-05-049, its 1995 ECAC proceeding, in which a Commission decision is pending. The ratemaking treatment of these credits is now in dispute, since it is likely that the ECAC and ERAM accounts will be eliminated or substantially modified.

11.7.1. The Utilities

PG&E recommends that, if sold, the economic portion of net excess emissions credits should be credited to the transition cost balancing account. Edison recommends that credits of record as of January 1, 1998 be market valued according to current year market prices and included as a credit against costs eligible for recovery through the transition cost balancing account. Edison proposes that when plants are market valued, the excess credits which have not yet been sold and are attributable to each facility could either be bundled with the plant or market valued separately. SDG&E recommends that if excess credits are sold prior to market valuation, the net proceeds should be credited to the transition cost balancing account, but believes that these values should be included in the market value of the plant unless they are sold prior to market valuation.

11.7.2. ORA and TURN

ORA recommends that any profit earned by the utilities from the sale of excess emissions credits which are not transferred to new owners through divestiture should be refunded directly to ratepayers, rather than being credited to the transition cost balancing account. TURN supports ORA's position.

ORA believes that simply crediting the value of these credits to the transition cost balancing account would defeat the Commission's stated purpose: to give the ratepayers the benefit of these sales. If these credits are used to offset transition costs, ORA believes that only shareholders would benefit, because such credits would serve to reduce the risk of transition cost recovery. Alternatively, ORA recommends that such proceeds be credited to a long-lived account, such as the account which will be established to track nuclear decommissioning expenses and revenues (as required by § 379), which would accomplish the Commission's intent by offsetting ratepayer costs.

11.7.3. Discussion

We will not adopt ORA's recommendation on this issue. The emissions credits do not fit the criteria listed in D.96-12-025, which established the Electric Deferred Refund Account for each utility. The sale of emissions credits results in a gain from a sale of utility property, rather than from utility overcollection or imprudent conduct. We agree with PG&E's assessment that sales of these assets are similar to sales of utility property, in which the gain on sale accrues to ratepayers. In D.97-04-024 and D.96-09-044, we determined that the appropriate way to flow a gain of sale of utility property to ratepayers is by crediting the proceeds to the transition cost balancing account. Similarly, crediting after-tax proceeds resulting from sales of emissions credits to the transition cost balancing account will help to ensure that the transition cost obligation can be recovered more quickly and the rate freeze ends more quickly.

By crediting such gains to the transition cost balancing account, we comply with § 367(b), which requires netting both above-market and below-market assets to determine the uneconomic piece of transition costs. Finally, crediting the transition cost balancing account rather than refunding these credits directly to ratepayers is consistent with our preference for the use of market-based mechanisms, in which the emissions credits are addressed during the market valuation process. To the extent that generating plant is retained, this credit should continue after the end of the transition period and will apply to offset post-2001 transition costs, as PG&E proposes.

11.8. Treatment of Land at Power Plant Sites for Divestiture

11.8.1. Utilities

PG&E states that it intends to package the relevant plant and associated generation assets, including land, in its divestiture offerings. This market valuation process would then result in a net credit or debit to the transition cost balancing account. As described above, PG&E believes that land must now be treated as depreciable property and proposes that all gains and losses realized through sale, spinoff, or appraisal of generation assets, including land, should flow back to ratepayers by way of the transition cost balancing account. PG&E believes this approach is consistent with TURN's proposal and states that to the extent the package is projected to be above-market, PG&E will accelerate amortization of the land, consistent with D.97-06-060.

In its divestiture application (A.96-11-046), Edison proposes to separate the land at its gas-fired fossil fuel sites as follows: 1) land necessary to operate the generating plant; 2) land to be sold separately; and 3) land to be retained by Edison for other purposes. Edison asserts that it has not yet determined the exact portion of land in each category and has therefore included all land at the generating stations as eligible for transition cost recovery. At market valuation or divestiture, Edison states that it will determine the appropriate disposition of the land and will then make the corresponding adjustments to the transition cost balancing account. Edison states that it has also identified a "proposal that would also allow the bidders for the plants to inspect the proposed property boundaries for themselves and propose minor boundary adjustments that may ease potential plant upgrade or repowering projects." (Edison's opening brief, p. 93.)

Edison recommends that land associated with transmission facilities should receive a full rate of return and should not be amortized on an accelerated basis. Edison explains that this land has been traditionally classified as generation assets in the vertically integrated utility. Edison proposes to retain land associated with fuel oil facilities until the ISO makes a determination as to the need for this dual fuel capability in the future. Edison recommends that if it is to retain these facilities for reliability purposes, they should be treated in the same manner as transmission assets; i.e., not subject to market valuation or accelerated depreciation. Edison recommends that all other land at its generating stations, whether proposed to be included in the divestiture transaction or not, should be classified as generation assets. Edison contends that no party, in any prior proceedings, has contended that it was improper to hold this land as generation assets. Edison agrees that this land eventually will be market valued and that the market valuation process will likely result in a credit to offset transition costs; however, Edison asserts that this determination cannot be made until divestiture is completed, at which time, Edison will know that boundaries of the divested land and any adjustments that might be required by various municipalities.

11.8.2. Intervenors

TURN argues that any land which is not included in the divestiture package must therefore not be required for the operation of the generating plants, by definition. This land should then be removed from rate base and treated as non-utility property. TURN recommends that such land should undergo market valuation as soon as possible and any net gains should accrue to ratepayers, who have been paying carrying costs on this investment for many years. TURN contends that this land should not be amortized at the beginning of the transition period and should not earn a rate of return prior to market valuation, because it is not needed for power plant operation or repowering and is therefore not utility property, a conclusion which TURN states is derived from Edison's position in the divestiture proceedings. TURN agrees that land related to transmission assets should not be market valued, but contends that land associated with fuel pipelines should be market valued and amortized at the reduced rate of return.

TURN maintains that none of the proposals for assigning differing rates of return to the various pieces of land can be implemented until Edison performs the necessary analysis of how much land should be assigned to each function or use at each plant. TURN recommends, therefore, allowing Edison to amortize only the book value of the land proposed to be divested until that analysis is completed. TURN recommends that Edison receive a reduced rate of return on all land until this analysis is complete. Upon completion, ratepayers would be refunded the return paid on land later found to be non-utility property and Edison would resume collecting a full rate of return on transmission-related land. In other words, TURN recommends that 1) land not needed for utility purposes would be removed from rate base on January 1, 1998, 2) the fair market value should be determined as quickly as possible, and 3) all net gains from increases in the land's value should accrue to Edison's ratepayers.

ORA supports TURN's recommendation to allow Edison to amortize only the book value of the land to be divested until further analysis is performed to accurately divide the land into pipeline-related land, transmission-related land, and other. Farm Bureau also supports TURN's recommendation to restrict Edison's recovery on the land it intends to retain. FEA recommends that any assets which have been used for generation functions in the past may be usable in other utility operations. Therefore, FEA maintains that it is questionable whether these assets are generation-related, and, in the case of land, whether these assets can be considered uneconomic. Enron also supports TURN's proposal.

11.8.3. Discussion

We have encouraged the divestiture of at least 50% of PG&E's and Edison's generation facilities in order to attempt to "resolve many, if not most, of the market power problems identified by the Department of Justice and FERC, and allow for a competitive market." (Preferred Policy Decision, mimeo. at p. 101.) To provide an incentive for these transactions, we allowed an increase in the reduced rate of return applicable to the utilities' non-nuclear and non-hydroelectric equity components of up to 10 basis points for each 10% of fossil generating capacity divested. These approaches were affirmed in D.96-12-088 and D.97-02-021. The Preferred Policy Decision provides this incentive only for the non-nuclear and non-hydroelectric equity components. PG&E and Edison should include proposals for computing and applying this incentive in their respective divestiture proceedings. PG&E and Edison should establish tracking accounts to track the differential in the rate of return as each 10% of fossil generating capacity is divested, which would then be applied to the reduced rate base.

Section 330(e) confirms the state's intent to reap the benefits of competition in the generation of electricity and § 330(l)(3) documents the Legislature's concern regarding market power. Furthermore,§ 367(b) requires market valuation "for those assets subject to valuation" by the end of 2001. It is indisputable, therefore, that market valuation and, in this particular case, divestiture, accomplishes two goals: 1) to ensure that "no participant in these new market institutions has the ability to exercise significant market power so that operation of the new market institutions would be distorted;" and 2) to transition the utilities from regulated status to unregulated status (§ 330(l)(2)). Both §§ 330 and 367 require that a netting calculation of all "above-market" and "below-market" transition cost assets be performed to determine the costs to be recovered. Section 330 requires that the transition to a competitive market be orderly, allow the utilities a fair opportunity to fully recover the costs associated with commission-approved generation-related assets and obligations, and be completed as expeditiously as possible. These two mandates demonstrate our duty to ensure that the market valuation process is structured as to obtain maximum value of the property.

In D.97-06-060, we found that the interests of both ratepayers and shareholders would be aligned in developing a methodology to collect transition costs as expeditiously as possible. Similarly, obtaining the maximum assessment of fair market value in an arms-length transaction benefits both the ratepayers and shareholders. Shareholders are not at risk for recovery of as many uneconomic costs and ratepayers may benefit by an early end to the rate freeze.

Edison indicates that it plans to divest only the "footprint" of land that its generation facilities occupy, but would give bidders the option of requesting more land as needed. The lands that Edison intends to retain are similar in nature to property that the utility previously held as Plant Held for Future Use (PHFU). We believe the principles underlying PHFU treatment apply equally to the generating plant-related land that Edison does not propose to divest with its generating plants. Edison believes that TURN's proposal should be dismissed as retroactive ratemaking and alleges that it is appropriate to retain the PHFU land until a favorable market arises for the land. At that point, Edison says, the utility will sell the land and apply proceeds from the sale to offset transition costs.

PHFU property may be included in a utility's rate base, as established in guidelines adopted as Appendix B in D.87-12-066, in Edison's 1988 general rate case. These guidelines clarify that, under certain circumstances, we will include PHFU in rate base. We have also determined that "[n]othing in this exhibit should be interpreted as precluding the ability of the ratepayers to recover gains on sales of plant that has at some time earned a return as PHFU." (D.87-12-066, mimeo. Appendix B at p. 4.)

In addition, § 728.1(c) sets forth standards for returning to ratepayers funds realized from a gain on sale of PHFU property. It requires that gains on sale of PHFU property that was included in rate base be allocated to customers in a manner consistent with Account 105 of the Uniform System of Accounts. It then directs that

> "the portion of the gains allocated to customers shall not be less than the amount the corporation has recovered through rates for the carrying costs and other expenses of the property during the period it was carried in the plant held for future use, and shall not exceed the gain on the sale, net of any tax, resulting from the sale."

It is reasonable to adopt TURN's proposal with certain modifications. By valuing a property right after it is taken out of rate base, the Commission could eliminate future uncertainty as to dividing the property's value pursuant to § 728.1(c). Assuming that the property had been in rate base since purchase, all gain in value since then would be attributable to ratepayers. Assigning value immediately might also immunize ratepayers from any speculation by the utility (e.g., if the utility waited until after the real estate market plunged to sell the property). Most importantly, calculating the gain in value of the land upon divestiture allows us to derive the necessary information to determine whether assets are or are not economic.

While Edison argues that retroactive ratemaking bars us from implementing TURN's proposal, we do not agree with this conclusion. We have previously concluded that an allocation of gain does not constitute retroactive ratemaking, since no adjustment is made to previously collected rates results. (56 CPUC 2d 4, 16.) Rather, we have imposed corrective actions to remedy past overcollections based on a utility's failure to comply with established accounting rules.

We direct Edison to allocate its land according to its function; i.e., transmission-related, fuel oil pipeline-related, and generating plant-related land, using a pro-rata analysis. The transmission-related land will receive the full rate of return and will not impact transition cost recovery. Edison's pro rata approach should be filed on March 2, 1998, in its appraisal application. Consistent with our approach toward fuel oil inventory, Edison should amortize the pro-rata portion of the land associated with fuel-oil pipeline and should include its proposal for the treatment of this land in the proposal for fuel oil inventory, to be filed on March 2, 1998, as discussed previously. All other land, traditionally classified as generation, but not divested with the plant, will be removed from rate base as of January 1, 1998. Only the book value of the land which is proposed to be divested and which is attributable to fuel oil pipelines will be amortized in the transition cost balancing account at the reduced rate of return until further analysis confirming these pro-rata approaches is complete and appraisal of the land is completed. Thus, other than land which is allocated to the transmission function and fuel oil pipelines, all generation-related land attributable to plant which is proposed to be divested should be removed from rate base as of January 1, 1998. We will order Edison to adjust its transition cost balancing account once the land is fully analyzed according to its various functions and undergoes market valuation. In this way, any gains can be quickly applied to offset transaction costs.

If not sold or market valued prior to divestiture, the date of divestiture is a reasonable date for this valuation to occur. At that point, we will know exactly what property the winning bidder requires and any adjustments that are required by various municipalities. The land can then be appraised and valued and the appropriate credits can be recorded in the transition cost balancing account. We are not convinced that there are such unique qualities to this land which would argue that we should wait until market valuation procedures for retained assets are in place. As with our prior examples, land is very different from power plants. We will review such assessments in the annual transition cost proceedings for reasonableness. This is a simple, uniform policy to apply, particularly because PG&E has already stated that it intends to include the land surrounding its power plants for divestiture, other than land needed for other utility purposes.

11.9. Step-up Transformers and Generation Radial Tie-Lines

On April 29, 1996, PG&E, Edison, and SDG&E filed a joint Petition for Declaratory Order (Docket No. EL96-48) with FERC, which asked for confirmation of a proposed delineation of certain facilities as either local distribution or transmission facilities. Edison proposed that all generation step-up facilities, except those at the San Onofre Nuclear Generating Station (SONGS), be reclassified for ratemaking purposes as generation. Edison also proposed that the SONGS step-up transformers and generation radial tie-lines connecting generators to the transmission grid remain classified as transmission for ratemaking purposes. In its comments, this Commission supported this proposed delineation, but recommended classifying the SONGS step-up transformers and generation radial tie-lines as generation. On October 30, 1996, FERC issued its Order in Docket No. EL96-48, which adopted the proposed delineation of facilities with this Commission's modifications. In D.97-05-053, we granted Edison's petition to modify D.96-01-011 and D.96-04-059, and allowed Edison to add approximately $18.7 million of sunk costs associated with SONGS' step-up transformers to SONGS sunk costs. (D.97-05-053, mimeo. Conclusion of Law 3 at pp. 9 -10.)

No party disputes this issue. Since FERC has already reclassified generator step-up transformers and generation radial tie-lines as generation, it is reasonable to use that classification for transition cost ratemaking purposes. These assets should be added to the net book value of associated plant.

12. Nuclear Generation Transition Costs

Generally, the revenue requirement associated with nuclear facilities is not an issue to be determined in this proceeding. The amount of sunk costs and ICIP treatment for Diablo Canyon was considered in D.97-05-088; the treatment of Palo Verde Nuclear Generating Station was determined in D.96-12-083; and the treatment of SONGS was considered in D.96-01-011 and D.96-04-059. However, certain issues related to nuclear generation transition costs have been raised in Phase 2, including whether transition cost recovery for differences between ICIP costs and Power Exchange revenues is allowed for PG&E. We do not address issues previously addressed in D.97-08-056. Nuclear sunk costs are already being amortized at an accelerated rate, consistent with the respective decisions.

12.1. Diablo Canyon

In A.96-12-009, PG&E proposed to recover ICIP costs by way of a separate nonbypassable charge. PG&E has also expressed, in this proceeding, its willingness to recover these costs in the transition cost balancing account (RT: 2241; 2964-2965). D.97-08-056 precludes the use of a separate, nonbypassable charge for this cost.

PG&E explains that in D.97-05-088, we adopted a fixed ICIP amount which reflects the cost to ratepayers of kilowatt hours received from the plant. Power Exchange revenues from Diablo's output would be used to offset this fixed ICIP price, but to the extent Power Exchange revenues are greater or less than ICIP, the difference would result in a debit or credit to the transition cost balancing account. PG&E asserts that this relationship is consistent with and authorized by the Rate Restructuring

Settlement, which provides that if PG&E's actual incremental costs exceed the fixed ICIP prices, this difference (between actual and ICIP) would not be recoverable in the transition cost balancing account. PG&E does not believe that the Rate Restructuring Settlement precludes either the recovery or the crediting of the difference between ICIP and Power Exchange Revenues, as TURN contends.

TURN maintains that because the Rate Restructuring Settlement reads, in relevant part, that "[n]one of Diablo Canyon's incremental costs would be eligible for recovery through the CTC," such recovery should, in fact, be banned. ORA does not believe that the Rate Restructuring Settlement is a document which binds this Commission in any way.

We agree with PG&E. As contemplated in both AB 1890 and the Preferred Policy Decision, it is the ongoing ICIP costs which are compared to the Power Exchange, and differences in revenues or costs are either credited or debited to the transition cost balancing account. Actual costs are not compared to the market clearing price for purposes of determining these ongoing transition costs. If the market-clearing price is below ICIP costs, this difference is debited to the transition cost balancing account. PG&E is at risk for any actual, incremental costs which are greater than ICIP. Similarly, if the market clearing price is greater than ICIP costs, this difference is credited to the transition cost balancing account. If actual costs are below ICIP costs, PG&E may retain the difference.

12.2. San Onofre Nuclear Generating Station (SONGS 2&3)

Edison states that it is making various necessary repairs to low-pressure steam turn rotors and exhaust hoods, which it asserts are necessary to maintain the safe and reliable operation of SONGS 2&3. Edison contends that shareholders made this investment with no guarantee of recovery and furthermore that there is no guarantee that Edison will realize any improvements in the capacity and output of SONGS. Edison asserts that any improvements which do occur would offset efficiency losses due to the units' aging. Edison notes that SONGS 2&3 have historically operated above and below their rated capacity during the last 10 years of operation. SDG&E agrees with

Edison's position that "the rated capacity of the unit is simply the vendor's guarantee that given a set of variables, their guarantee to the purchaser of the plant is that it will perform at least at this level." (RT at 1546.)

As a general proposal, TURN recommends that no ICIP costs be recoverable in the transition cost balancing account for any output significantly above current nameplate capacity due to plant retrofits. TURN makes this recommendation specifically for SONGS, because it believes that the repairs are likely to increase the capacity above nameplate capacity. ORA supports TURN's position.

EPUC recommends that the recovery of ICIP should be consistent with the requirements of the SONGS settlement, but notes that the limit for SONGS recovery is the ICIP compensation. EPUC therefore proposes that in the event that Power Exchange or other revenues exceed the ICIP, the transition cost balancing account be credited with the excess amount, which would then reduce transition costs. Similarly, in the event that there is a shortfall in revenues below the eligible ICIP level, EPUC recommends recovering this shortfall through the transition cost balancing account.

Under the terms adopted in D.96-04-059, Edison and SDG&E will recover the forecasted costs of operating the plant if SONGS 2&3 operate at a capacity factor of 78%. Actual costs above ICIP (i.e., if capacity is less) are not recoverable from ratepayers, while actual costs below ICIP (i.e., if the plant operates at a higher capacity factor) do not benefit ratepayers. Thus, if the plant's capacity were increased by these repairs, it would produce more kilowatt hours than it would have compared to the capacity factor adopted in D.96-04-059. Depending on the Power Exchange price, an increase in produced kilowatt hours has the potential to increase the transition costs claimed if the Power Exchange price is less than the forecasted ICIP price. Similarly, if the Power Exchange price is greater than forecasted ICIP prices, the increase in capacity has the potential to offset transition costs.

We do not choose to interfere, in this decision, with the balance of risk and rewards that was adopted concerning the ratemaking treatment of SONGS 2&3. These retrofits were undertaken for purposes of plant safety and reliability, *not* to increase plant capacity per se. Recovery of the differences between ICIP prices and Power

Exchange clearing prices was intended by the Preferred Policy Decision and provided for in AB 1890. Therefore, we will rely on the ICIP prices adopted in D.96-04-059 to compute any necessary transition cost recovery or offsets.

Comparison of ICIP costs with the market-clearing price is different for purposes of computing ongoing transition costs, if any, related to the Palo Verde Nuclear Generating Station. In D.96-12-083, we established balancing account treatment for these ICIP costs, consistent with the settlement agreement proposed by the parties and adopted in that decision. Because of this balancing account treatment, we will compare Palo Verde's incremental operating costs as billed by the Arizona Public Service, the plant's operator, with the market-clearing price, rather than the fixed ICIP costs approach which we have implemented for Diablo Canyon and SONGS 2&3.

13. Fuel and Fuel Transportation Contract Transition Costs

Section 367(c) includes fuel and fuel transportation costs as going forward costs, which must be recovered from market revenues and which are specifically excluded from transition cost recovery, with two limited exceptions identified in § 367(c)(1) and (c)(2). Despite this guidance, these issues have generated great controversy.

13.1. PG&E

For generating facilities that are designated as must-run by the ISO, PG&E asks for the opportunity to seek recovery of all fixed fuel and fuel transportation costs through the transition cost balancing account if these costs are not recovered through the ISO contracts. PG&E explains that it would reserve a placeholder for these costs and recovery of any costs not covered by ISO revenues should be considered by the Commission if and when PG&E actually seeks such recovery. As discussed previously, we deny this request.

For non-must-run generating facilities, PG&E is not seeking transition cost treatment of any uneconomic costs of the demand charge, customer access charge and Transwestern reservation charge associated with these facilities, consistent with its agreements in the Rate Restructuring Settlement. However, PG&E is seeking a placeholder to allow recovery of the uneconomic costs of the Interstate Transition Cost

Surcharge (ITCS) and geothermal minimum take-or-pay obligations associated with the non-must-run facilities. PG&E identified these costs as $255.7 million (Geysers steam purchases of $215.2 million and ITCS costs of $40.5 million). PG&E does not seek recovery of these costs as of January 1, 1998, but instead proposes to seek Commission approval if they are actually incurred during the transition period, to the extent these costs are not otherwise recovered from Power Exchange or ISO revenues.

The audit report accepted these costs as eligible for transition cost recovery, but proposed to increase the Geysers contracts by $53.8 million, which are year 2000 costs for this contract which were omitted from the filing. The auditors also questioned the ITCS amount, because we have not previously approved this amount.

PG&E asserts that AB 1890 gives the Commission the option to determine that categories of fuel costs that are going forward costs and fixed obligations are eligible for transition cost recovery for non-must-run plants, particularly in light of the use of the term, "generation-related assets and obligations" in § 367. PG&E also asserts that this language reflects the Preferred Policy Decision, which allows recovery of "fixed obligations directly related" to the generation asset. (Preferred Policy Decision, mimeo. at p. 115.)

PG&E maintains that ITCS costs are comparable to a generation-related regulatory asset and should be eligible for transition cost recovery. These costs are a result of PG&E entering into various interstate gas transportation contracts prior to the unbundling of the gas industry. PG&E explains that it entered into these contracts to ensure that it could provide services needed for its gas users, including its own fossil-generation facilities (or Utility Electric Generator, UEG). Because it entered into these contracts to provide bundled service to its own electric generation, a portion of the capacity under these gas contracts was expected to be allocated to PG&E's UEG. Capacity brokering and the ITCS balancing account delayed the payment of these costs and PG&E now asserts that these gas transportation contracts should be categorized as a generation-related asset and cannot be considered a going-forward cost. PG&E asserts that these costs are given balancing account treatment and any undercollection of ITCS from noncore customers will be allocated to the noncore customers in the next Biennial

Cost Allocation Proceeding (BCAP); therefore, these costs represent a fixed obligation of noncore customers. PG&E admits that its UEG pays these costs through a volumetric charge, but states that it is possible these costs could be included in the demand charge for the next BCAP cycle.

PG&E explains that the auditors questioned $40.5 million related to ITCS only because this amount has not received Commission approval for 1998 and 1999. PG&E expects an allocation of ITCS costs in the next BCAP similar to the $40.5 million allocated to PG&E's UEG in the 1996-97 cycle.

PG&E also believes that fixed geothermal steam fuel-related obligations are eligible for recovery in the transition cost balancing account, as discussed in Section 16. PG&E seeks authorization to request recovery of these costs if they are not recovered in the market. PG&E believes that to the extent operations of its geothermal facilities are suspended, it would incur take-or-pay costs, which would be a fixed obligation. Secondly, PG&E explains that § 367(c) applies specifically to fossil fuel facilities and not to geothermal facilities. PG&E states that from a policy perspective going-forward costs of geothermal facilities should be treated differently from going forward fossil costs, and explains that geothermal steam contracts are unique in that there is no other use for this steam.

13.2. Edison

Section 367(c)(2) allows Edison to recover 100% of the uneconomic portion of the fixed costs paid under fuel and fuel transportation contracts, with the following requirements: 1) the fuel and fuel transportation contracts had to be executed prior to December 20, 1995 and 2) these contracts must be determined to be reasonable by this Commission. As of January 1, 1998, Edison estimates that it will incur $840.5 million in cumulative, unavoidable fixed costs under fuel and fuel transportation contracts for the transition period ($389.9 million in gas contracts and $450.7 million in coal contracts). These costs would be netted against the market value of the fuel to obtain the uneconomic portion, or the amount to be collected through transition cost recovery. Edison states that it captures the market value of the gas contracts, which are credited against transition costs and thereby reduce the total amount to be collected. Edison does not believe that there is a ready market for coal which would allow similar calculations to be made.

Similar to the position of several intervenors, Edison maintains that ITCS gas costs are a going forward cost, and therefore should be recovered through market prices. However, Edison states that if we find that PG&E's ITCS costs can be recovered through the transition cost balancing account, the same treatment should be afforded to Edison.

Edison explains that its fuel and fuel transportation contracts are eligible for recovery under the exception granted in § 367(c)(2). Edison proposes to determine its unavoidable gas costs monthly and to book costs associated with contracts pending reasonableness review to the transition cost balancing account, subject to later true-up. Edison contends that this approach is reasonable because it is consistent with current ECAC procedures, it will not impact Edison's ability to recover such costs during the transition period, and ratepayers will be unaffected because of the rate freeze. Edison states that a settlement agreement related to Canadian gas reasonableness issues has been reached with ORA and submitted to the Commission in A.93-05-044 *et al.*, which would make the necessary reasonableness findings, if adopted by the Commission.

Edison asserts that all unavoidable fuel contract costs found reasonable by this Commission must be eligible for transition costs recovery. Edison explains that many of its long-term gas contracts include terms which require Edison to pay the supplier regardless of the quantity of gas which is actually scheduled. Edison considers these costs unavoidable. Edison also explains that contracts which do not require Edison to schedule minimum quantities or make fixed payments regardless of the quantity of gas taken are not considered unavoidable or fixed obligations, and therefore does not request transition cost recovery for these costs.

Edison entered into long-term coal contracts to supply its Four Corners and Mohave generating stations. Edison states that certain costs related to these contracts are unavoidable or fixed and furthermore, certain costs may arise in the future which become unavoidable. For example, Edison has entered into contracts to supply coal to the Mohave generating station, which requires Edison to pay certain costs regardless of the quantity of coal taken. Variable costs are costs that depend on the quantity scheduled and can be avoided if Edison does not schedule any coal under its contracts.

As we have previously explained, Edison takes three steps in determining fossil-related transition costs. First, Edison determines eligible transition costs (including fuel and fuel transportation contracts) and then nets out benefits associated with emissions credits and allowances and gas market revenues. Second, Edison calculates offsets to the net eligible transition costs, which includes credits such as its proposed gas purchase credit. The gas purchase credits are designed to equal the market value of Edison's gas contracts that are used to provide gas for electric generation. Edison proposes to determine credits separately for must-run and non-must-run units. Finally, these offsets are deducted from the net eligible transition costs to arrive at the uneconomic costs which Edison believes it should have the opportunity to collect through transition cost recovery.

Under Edison's proposal, the market value of gas is used to determine the going forward costs recoverable from market revenues, which help to offset the unavoidable costs of Edison's long-term gas supply and gas transportation contracts. Edison states that this credit is designed to approximate the amount of net revenue that Edison would have received if it sold its gas at market prices rather than using the gas for generation.

Edison explains that to determine whether there will be an offset to eligible transition costs, the variable costs of fuel must be estimated for both gas-fired and coal-fired generation. In addition, if Edison resells to third parties any gas transportation or gas that it must purchase, this results in a benefit that offsets these eligible transition costs. The net eligible transition cost determination is a result of offsetting eligible transition costs with the appropriate benefits (including emissions credits). We have already disposed of Edison's proposed incremental capital cost credit, its proposed 150 basis point equity earnback, and its Power Exchange/ISO revenue credit, and will now address its proposed gas purchase credit.

The gas purchase credit is an offset to the calculation of net eligible transition costs and reflects the fact that Edison's actual variable costs may differ from the costs Edison would have paid if it had purchased its gas and gas-related services in the gas market (also called the gas dispatch price).[21] The dispatch cost is defined as the forecast market value of the gas and gas transportation consumed in order to generate the forecast gigawatt hours. Edison believes that this gas purchase credit is necessary for two reasons: 1) Edison has entered into gas and gas transportation contracts under which it pays an unavoidable (fixed) cost and a variable cost, and this variable cost may be below the market clearing price for the same commodity or service; and 2) Edison also uses gas and gas transportation purchased under must-take contracts with very low variable costs. Edison states that whether or not it earns market revenues to cover its incremental costs, the gas purchase credit would be used to offset eligible transition costs so that Edison's distribution customers would receive the economic value of these contracts that were entered into on their behalf.

Edison explains that the gas purchase credit represents the portion of its unavoidable gas contract costs which are recoverable from the market; in other words, these costs are economic and so are credited back to offset transition costs. Edison believes that the gas purchase credit must be calculated differently for must-run and non-must-run plants. We note that Edison has an application pending to divest all of its gas-fired plants; once divestiture occurs, it is only the coal-fired plants that will be the subject of this recovery requirement.

For must-run plants, Edison proposes to calculate its gas purchase credit differently, because it has proposed a Power Exchange revenue crediting mechanism based on different variable costs. The actual workings of the proposed gas purchase credit appear to be the same for both must-run and non-must-run plants, however,

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[21] This would be an important step in Edison's revenue crediting proposal, because as Edison explains further, in calculating its incremental costs to determine the Power Exchange/ISO revenue credit, the gas burned is valued at the gas market price or dispatch price of gas. We have rejected this proposal.

except for an adjustment which Edison states is necessary because the gas dispatch cost is based on a deemed quantity of gas from the unit heat rate curves, whereas the variable cost of gas is based on the actual quantity of gas consumed at the unit. Edison states that whether or not there is a Power Exchange/ISO revenue credit available for must-run units, the gas purchase credit must offset eligible transition costs so that the economic value associated with these long-term fuel contracts is passed on to ratepayers.

Edison forecasts its 1998 variable gas costs, based on the 1998 forecast gas burn, the California border price forecast, the forecast gas supply basin prices, and the forecast interstate and intrastate transportation rates. Edison sequences the available gas supplies based on incremental cost to meet its total forecast gas demand, which is the methodology used in its most recent ECAC forecast. Edison then calculates its forecast of 1998 Gas Dispatch Costs based on the California border gas price forecast. For units served by Southern California Gas Company (SoCalGas), the forecast border price plus the forecast SoCalGas tariff rate (intrastate transportation rate) plus the municipal surcharge equals the forecast gas dispatch price. For Mandalay Generating station, which is under a bypass deferral agreement with SoCalGas, the forecast contract rate plus the municipal surcharge is added to the forecast border price to obtain the gas dispatch price. For Cool Water generating station, which is served directly by the Kern River and Mojave interstate pipelines, the forecast gas dispatch price assumes gas will be transported to Cool Water on the Mojave pipeline. The forecast gas dispatch cost for 1998 is obtained by multiplying the monthly gas dispatch price at each station by the forecast gas burn at that station.

For variable coal costs, Edison estimates its forecast using the same methodology that Edison uses in ECAC proceedings. This methodology begins with recorded coal costs and forecasts future coal costs based on forecast inflation rates for the various cost components. Edison does not believe there is any portion of the unavoidable costs of the coal contracts which is economic, because there is no market available for the sale of coal received under these contracts. Edison asserts that there cannot be a market because the coal mines and the coal plants are remote and lack access to coal markets.

Two major issues have been raised regarding the gas purchase credit. EPUC and CIU argue that this credit should always be equal to or greater than zero. CIU is concerned that under Edison's gas purchase credit proposal, if the variable cost of gas were to exceed its estimate of the market price, it appears that Edison would seek transition cost recovery for certain gas costs. EPUC also questions the use of the intrastate transportation cost in calculating the gas purchase credit and maintains that if it is used in establishing the dispatch price, it should never be lower than Edison's actual intrastate transportation cost. Edison counters these concerns by stating that because the dispatch price is based on the California border price and actual intrastate transportation rates, the actual variable gas costs are not likely to exceed the gas dispatch price on a monthly basis, if Edison continues to use gas under its existing long-term contracts. Edison also asserts that a negative credit is unlikely because Edison's incentive is to reduce the level of transition costs.

Because Edison sequences the purchase of available gas supplies based on incremental cost to meets its forecasted gas demand, it would not utilize its long-term contracts if the variable costs incurred under these contracts exceeded the gas dispatch price, because it would be more economical for Edison to purchase gas at current market prices. However, Edison objects to limiting the gas purchase credit to be at least equal to zero. Edison maintains that it is possible for the gas purchase credit to decline as Edison divests its plants, buys out or buys down to market its long-term gas contracts, or elects to sell its gas supplies and gas transportation capacity on a shorter-term basis. Edison states that the gas purchase credit is just one of the offsets to fossil net eligible transition costs. Edison has testified that, in the aggregate, such offsets cannot be less than zero; thus, a negative gas purchase credit cannot result in a recovery of more than the net eligible transition costs. (RT: 2249-2250.)

The gas dispatch price used in the above calculations is based on published tariffs and market indices and is a proxy for actual market price of gas. In general, Edison agrees with EPUC that the "deemed" intrastate transportation cost and the actual intrastate transportation costs will be identical, but would like to allow for the possibility of differences. Edison expects that it is possible to negotiate a rate with its supplier that is less than tariff rates, which would then increase the gas purchase credit. EPUC contemplates a situation which would result in rates higher than tariff rates, which have the potential of increasing transition costs. While Edison expects that this is an unlikely outcome, it objects to EPUC's recommendation that the cost used in the benchmark (i.e., the gas dispatch price) should never be lower than Edison's actual intrastate transportation costs.

Edison believes that its coal supply and coal transportation have unique characteristics affecting the determination of uneconomic costs. Because there is not an active competitive market for coal supplies, unlike gas generation, Edison assets that it is impossible to determine the uneconomic or economic portion of the coal contract costs in isolation. Edison therefore proposes to use the economics of the entire coal plant and its output as the best proxy for determining the uneconomic portion of the fixed costs of the coal contracts. Edison recommends that all fixed, unavoidable costs of the coal contracts be considered eligible for transition cost recovery and that the market value of the generation associated with Four Corners and Mohave be credited to offset these costs; this would result in only the uneconomic generation costs being recovered as transition costs. Edison believes this approach would be consistent with market valuation of these facilities, in that it expects the coal contracts would be included with the plants and the bid price would reflect any uneconomic features of the coal contracts.

Edison asserts that the take-or-pay obligations of the Four Corners coal contract represent a fixed cost eligible for recovery, because payments for the minimum quantity are required and unavoidable. Edison disputes TURN's contention that the take-or-pay obligation is not eligible for transition cost recovery unless the take-or-pay limit is reached. Edison also disputes TURN's contention that the costs that Edison may incur under its existing coal supply contracts for mine closings and reclamation are speculative and should be excluded. Edison believes that to the extent it has any liability for mine closing and reclamation costs, which are in dispute, and actually incurs costs, those costs should be recoverable as transition costs. Edison also explains that any recovery of employee retirement costs will be based on actual costs, rather than estimates.

The auditors questioned various contracts, because they have not yet been approved by the Commission, and proposed other adjustments related to calculation errors. These adjustments would reduce unavoidable gas contract costs from $389.9 million to $70.7 million. Similar adjustments for coal contracts would reduce the amounts from $450.7 million to $419.1 million. The auditors include adjustments to the coal contracts to reflect the fact that Edison is not specifically responsible for certain retirement costs and mine closing costs under the Peabody and BHP coal mine contracts. The auditors acknowledge that Edison is disputing these items with the suppliers and may ultimately be responsible for some or all of these costs.

The auditors also question the allocation of fixed unavoidable costs under the Peabody contract, because they believe this allocation overstates Edison's long-run unavoidable obligations. The audit report explains that Edison's methodology is only accurate assuming normal operation of the Mohave power plant and recommends that we review Edison's assumptions regarding this contract's fixed and variable costs. Edison assumes that unavoidable labor and material costs are independent of delivered coal tonnage over the life of the contract. The auditors clarify that while this assumption may be reliable for short-term variations in tonnage, it may not be true for long-term tonnage change. The auditors believe an adjustment may be necessary, but cannot quantify it, because Edison's contract cost forecasting model assumes labor and material costs are independent of tonnage.

13.3. SDG&E

SDG&E seeks recovery of fixed transportation costs allocated to its UEG, pursuant to its BCAP. SDG&E estimates these costs at $38.7 million, excluding natural gas storage costs. SDG&E concurs with the audit adjustment in removing the storage costs. The auditors question the remaining UEG costs, which they explain might not be recoverable if SDG&E's plants are not considered reliability plants and because the regulatory foundation for their inclusion is unclear.

SDG&E asserts that these costs represent a regulatory obligation which SDG&E will incur whether or not its units are designated must-run by the ISO. SDG&E has proposed that all of its non-nuclear generating units are needed for reliability purposes and therefore expects to enter into must-run agreements with the ISO, which will include the BCAP fixed transportation expense. To the extent that must-run agreements are not executed for certain units by the ISO, SDG&E would then decide whether to operate those plants or shut them down. SDG&E acknowledges that if it chooses to operate these plants, SDG&E would be at risk for the BCAP fixed transportation costs as a going forward cost.

However, SDG&E states that if it decides to shut down these units, the BCAP fixed transportation costs would then be a regulatory obligation recoverable as a transition cost. Furthermore, SDG&E concurs with PG&E's position and states that to the extent a plant is designated as must-run and all costs are not fully recovered by the ISO or Power Exchange revenues, Commission-approved costs should be eligible for recovery in the transition cost balancing account.

13.4. ORA

ORA recommends that for non-must-run units, fixed costs related to fuel and fuel transportation contracts should be eligible for transition cost recovery only for Edison and then only to the extent that these costs are reasonable and uneconomic. ORA states that Edison's fixed fuel contract costs can be considered uneconomic only if Power Exchange revenues are less than all going forward costs, and the uneconomic amount is the difference between the Power Exchange revenues and all going forward costs.

ORA agrees the proposed settlement agreement if adopted in A.93-05-044 *et al.*, would resolve the issues of reasonableness of Edison's gas supply and gas transportation contracts and would describe the aspects of the contracts which we should consider reasonable for transition cost purposes. ORA explains that the portion of the reasonable costs that are uneconomic would be determined through the operation of the revenue crediting mechanism. According to ORA, the proposed settlement would resolve cost allocation issues associated with any buy-downs or buy-outs of these contracts. If the settlement is not adopted, reasonableness reviews would be necessary in the annual transition cost proceedings.

ORA is particularly concerned regarding the treatment of fixed uneconomic coal contract costs, because Edison is planning to divest all of its gas-fired fossil plants. Edison has identified these fixed costs as approximately $108 million in 1998. ORA considers only that portion of fixed fuel and fuel transportation costs which cannot be recovered from the Power Exchange to be uneconomic, while Edison defines all fixed fuel and fuel transportation costs associated with coal take-or-pay arrangements to be uneconomic. Using its methodology and Edison's estimates for 1998, ORA estimates that Power Exchange revenues compared with all going forward costs, including the fixed coal contract costs, will recover all but $2.3 million of the fixed coal contract costs.

ORA asserts that PG&E and SDG&E should not be allowed to recover any fixed costs associated with gas supply or transportation, because it is possible to manipulate fixed costs by converting variable to fixed charges. ORA maintains that if PG&E does not generate electricity from its gas-fired plants after January 1, 1998, it will not incur ITCS costs, which ORA maintains PG&E's electric department has no obligation to pay. ORA explains that these costs are not caused by electric restructuring, but were the result of gas industry restructuring and are costs faced by all competitors in the generation market. ORA thinks that PG&E's fixed take-or-pay costs associated with geothermal fuel are analogous to fixed fuel costs of fossil plants, and asserts that these costs should not be recoverable through the transition cost balancing account; rather, these costs should become part of the geothermal revenue requirement, to be established in A.96-07-009. As discussed in Section 16, ORA recommends that only credits resulting from the difference between Power Exchange revenues and the geothermal revenue requirement should flow through the transition cost balancing account.

13.5. TURN

TURN believes that our determination of fuel contract costs and their ultimate recovery is one of the most critical issues in this proceeding. TURN agrees with ORA that Edison may recover fuel and fuel transportation charges through transition cost recovery only to the extent that the Power Exchange price does not cover all going forward costs, including fuel and O&M costs. TURN asserts that Edison's take-or-pay costs are not stranded costs unless the take-or-pay obligation is actually incurred. In addition, TURN maintains that Edison's coal plants produce electricity at per kilowatt-hour costs that are below the expected Power Exchange price, even when the take-or-pay costs are included. TURN therefore asserts that it is unreasonable that Edison receive funding through transition cost recovery for a plant that is actually economic.

TURN also asserts that the appropriate cut-off date for considering the contracts reasonable is April 20, 1994, the date the electric restructuring rulemaking was issued. TURN observes that Edison's gas service with Southwest Gas was renegotiated on November 29, 1995. Prior to this time, Edison took tariffed service from Southwest Gas, which included a fuel price based entirely on volumetric usage. The new contract includes a fixed charge rate component, which now may be eligible for transition cost recovery. TURN looks askance at these facts and asks that the Commission consider the dates of contract execution in its determination of reasonableness.

TURN recommends excluding the potential charge for reclamation and closure costs associated with Edison's coal contracts from transition cost recovery. While TURN acknowledges that Edison is seeking a placeholder in the transition cost balancing account for these costs, should they be incurred during the transition period, TURN recommends that they be deemed presumptively unreasonable. TURN maintains that Edison should be required to make a detailed showing of any actual costs incurred in this regard. TURN explains that this higher standard is reasonable is because this category of risk is the product of Edison's choice to invest in coal plants.

TURN explains that, with few exceptions, every fossil fuel generation plant operator must pay to transport fuel to its power plants and contends that PG&E and SDG&E are not allowed to recover fuel costs under AB 1890, but must recover them from the market. TURN asserts that the dispatch cost assigned to a plant under regulation is not useful in terms of determining what is variable and fixed in the competitive generation market after January 1, 1998. Rather, TURN recommends that the bid price is the relevant information to consider and that recovery of ITCS costs through the transition cost balancing account would allow PG&E and SDG&E to make lower bids into the Power Exchange than they would otherwise be able to make if they had to recover all their costs from the Power Exchange price. Furthermore, TURN notes that PG&E has acknowledged that the Gas Accord's provisions (adopted in D.97-08-055) dispose of the ITCS cost issue.

13.6. FEA

FEA agrees that certain of Edison's fuel and fuel transportation costs are eligible for transition cost treatment under § 367(c)(2), but PG&E and SDG&E must recover these costs through the market as going forward costs. FEA asserts that the utilities have a duty to mitigate such costs, which cannot be considered an obligation for purposes of transition cost recovery. FEA maintains that the specific provisions of § 367(c) override the broad definition of costs eligible for transition cost recovery in § 367. FEA recommends excluding from transition cost recovery any costs whose eligibility for transition cost recovery depends on the need for plant reliability until that need has been finally determined.

FEA agrees that until costs are determined to be reasonable, Edison's fuel and fuel contracts are not eligible for transition cost recovery. FEA also recommends that certain coal mine closing and reclamation costs, as well as associated employee retirement costs, be ineligible for transition cost recovery at this time, because Edison is disputing whether it is liable for these costs.

13.7. CIU

CIU agrees with FEA that only Edison's fuel and fuel transportation costs are eligible for recovery, pursuant to § 367(c)(2). CIU concurs that PG&E's and SDG&E's fuel costs are excluded as going forward costs, because the general language of § 367 is expressly limited by the more specific language of § 367(c)(2). CIU disputes PG&E's

contention that take-or-pay costs associated with geothermal steam contracts are eligible for transition cost recovery. These costs do not fall under § 367(c), because they are not fossil units; nor can they be considered eligible for recovery under § 367, CIU contends, because these are contractual obligations, rather than a generation facility, nuclear settlement, purchased power contract, or regulatory asset.

CIU agrees that ITCS costs are a going forward cost. CIU explains that demand charges paid to SoCalGas and PG&E for intrastate transportation pipelines are not eligible for transition cost recovery except under certain limited circumstances. For Edison, CIU contends that these demand charges may be eligible only if they are part of a fixed transportation contract entered into prior to December 20, 1995 and cause the cost of electricity generated by the facility to be uneconomic. For PG&E and SDG&E, even if such demand charges are "akin" to generation-related obligations, CIU contends they cannot be included in the uneconomic portion of net book value of fossil plants, as provided for in § 367(c).

CIU concurs with other intervenors that Edison's proposed treatment of coal and gas contracts is inappropriate and has the potential of increasing transition cost recovery. CIU recommends a very limited application of § 367(c)(2) regarding Edison's coal contracts: if Power Exchange revenues (including revenues derived from sales of ancillary services and other products to the ISO) exceed Edison's costs of producing power from these plants (including net book value, return, going forward costs, and fixed fuel costs), no costs associated with these plants would be added to the transition cost balancing account; thus, these contracts would be eligible for recovery only to the extent that Power Exchange revenues derived from all fossil-fuel facilities are insufficient to recover the costs associated with these facilities. After market valuation, the positive or negative net value of the plants would be credited or debited to the transition cost balancing account.

13.8. EPUC

EPUC agrees with ORA that our review of Edison's gas costs must focus on determining which costs are fixed, which of those fixed costs are uneconomic, and which costs are reasonable. EPUC also agrees that our acceptance of the settlement pending in A.93-05-044 *et al.* will ultimately determine the reasonableness of the subject contracts; however, there may be certain accounting issues which must receive further consideration in the annual transition cost proceeding. EPUC maintains that Edison's gas purchase credit should have a safeguard and never be recorded as less than zero. Without this safeguard, EPUC believes Edison would recover more than the statute allows for the uneconomic portion of the fixed gas costs. The intrastate gas transportation rate is a component of both the gas purchase credit calculation and the Power Exchange/ISO revenue credit calculation. EPUC recommends using identical rates in the dispatch gas price (to calculate the gas purchase credit) and the actual gas price (to calculate the Power Exchange/ISO revenue credit). EPUC believes this approach will ensure consistency and avoiding any mismatching between booked costs and revenues.

13.9. IEP

IEP recommends that for those units classified as must-run by the ISO, the only going forward costs eligible for recovery in the transition cost balancing account, including fuel and fuel transportation costs, are those costs incurred in the hours when the ISO actually calls upon the plants to provide the relevant services, not for the duration of the contracts. This recommendation is further limited to the uneconomic costs, i.e., those costs not recovered through market revenues.

For PG&E's and SDG&E's non-must-run plants, IEP contends that no fuel and fuel transportation costs are eligible for transition cost recovery, because these are going forward costs. For Edison's non-must-run plants, only those costs that Edison demonstrates are within § 367(c)(2) are eligible for transition cost treatment; i.e., such costs must be uneconomic and must be found reasonable by this Commission. IEP asserts that Edison's proposed Mohave and Four Corners coal costs are not necessarily uneconomic, that the Canadian gas purchase and transportation contracts have not been found reasonable, and that the Wheeler Ridge Access charges are not uneconomic; these costs therefore are not eligible for transition cost treatment.

IEP states that ITCS costs are transition costs PG&E incurred as part of gas unbundling, and therefore are an obligation of its gas department. IEP argues that these costs cannot be regulatory obligations, as both PG&E and SDG&E assert, which would contravene the intentions of § 367.

IEP endorses ORA's and EPUC's criteria for determining whether Edison's fuel and fuel transportation costs are recoverable under § 367(c)(2). IEP is specifically concerned with Edison's proposal to recover all of its Canadian gas contract costs, at issue in A.93-05-044 *et al.*, pending Commission review, subject to later adjustment. IEP objects to this treatment because it could prolong the rate freeze, has the potential of allowing Edison the opportunity to over-recover costs and thus price its electricity lower and drive down market prices, and is contrary to the recently filed settlement agreement in A.93-05-044 *et al.* IEP suggests that, pending approval of this settlement, Edison be allowed to recover only 50% of its gas contract costs in the transition cost balancing account, subject to further true-up.

IEP also asserts that Edison's request to recover Wheeler Ridge access charges should be denied. Edison is seeking recovery of charges incurred to transport gas on the SoCalGas system. IEP believes that this contract does not meet the criteria of § 367(c)(2), because the charges Edison pays under this contract are the same as the SoCalGas tariff charges for use of the same Wheeler Ridge facilities. IEP maintains that this contract cannot be determined to be uneconomic, because Edison is paying the equivalent of market rates for Wheeler Ridge access service.

IEP disagrees with Edison's contention that it is impossible to measure the below-market portion of its coal contracts, and disputes Edison's contention that crediting any excess Power Exchange/ISO revenues to the transition cost balancing account is an appropriate remedy. IEP declares that the burden of proof is on Edison to demonstrate that these contracts are uneconomic. IEP recommends that it would be preferable to obtain a measure of the value of these contracts using the price of coal at other sources.

13.10. Discussion

We agree that fuel and fuel transportation costs are plainly delineated in § 367(c) as "going forward costs" of fossil plants, with the exceptions identified in § 367(c)(1) and § 367(c)(2). We do not agree with SDG&E's strained distinction between long-term contracts which Edison enters into and costs which we allocate to SDG&E's UEG customers in the BCAP. On this particular issue, the statutory language is plain and unambiguous: fuel and fuel transportation costs are going forward costs, with the exception of Edison's fuel and fuel transportation costs and operating costs for "particular utility-owned fossil power plants or units at particular times when reactive power/voltage support is not yet procurable at market-based rates." All other fuel costs must be recovered through market prices. We have stated our preference to use market mechanisms to determine transition costs to the extent possible. It is not necessary to provide transition cost treatment for units deemed necessary for reactive power/voltage support by the ISO. As previously discussed, we expect the utilities to negotiate vigorously with the ISO to develop appropriate contracts to cover costs. Certainly, if the ISO does not deem the operation of these units necessary and the utilities shut them down, as SDG&E alleges might occur, there is no reason ratepayers should continue to pay for UEG fixed gas transportation costs while receiving no benefits of the unit's operation. We find such a proposal troubling. We will not guarantee ratepayer recovery for these costs; to do so would not only increase transition costs in a manner that is not in compliance with the law.

We do not agree with TURN that the fuel contracts signed after the electric restructuring rulemaking was issued should receive additional scrutiny. As established by law, December 20, 1995 is the cut-off date to which we must adhere. Because certain of these contracts are being reviewed for reasonableness in other proceedings (e.g., A.93-05-014 *et al.*), Edison proposes to track these costs in the transition cost balancing account and then adjust them after the fact if any amounts are disallowed by this Commission. We will not allow this treatment. In the noted proceedings, a settlement was filed at this Commission on July 16, 1997. We expect to adopt a decision on this settlement by year-end. Until that time, however, such contract costs should be tracked in a memorandum account and transferred to the transition cost balancing account upon our determination of reasonableness. Again, we disagree with Edison's forced reading of the relevant code sections: it is not that reasonableness must be determined subsequent to transition cost recovery, but that reasonableness must be determined subsequent to execution, which must have occurred no later than December 20, 1995.

Edison's gas purchase credit proposal is needlessly complicated. Fuel costs should be excluded from the transition cost balancing account and recovered from Power Exchange revenues, ISO revenues, and any other market sources, to the extent possible. The same principles hold true for Edison, however, AB 1890 provides for recovery of the uneconomic fixed portion of these fuel and fuel transportation contracts. We prefer to avoid complicated regulatory approaches based on debatable assumptions and to focus on the market. We remain concerned that Edison's proposed treatment may result in ineligible costs being added to the transition cost balancing account, which is not only contrary to our stated policy, but unlawful. Edison's fuel and fuel transportation contracts must first be found reasonable by this Commission. Once that hurdle is cleared, it is the uneconomic fixed costs that may be eligible for transition cost treatment. To the extent Edison cannot receive these costs from market revenues, including the take-or-pay provisions of fuel contracts, Edison may seek transition costs recovery of the demonstrably uneconomic fixed portion of these costs.

Only if market revenues are not sufficient to cover all going forward costs will we allow that portion of the fixed costs which exceeds these revenues to be added to the transition cost balancing account. This market-based approach has the distinct advantage of being relatively simple to implement and intuitively easy to grasp. By using the market to determine the uneconomic fixed costs, we avoid complicated, short-lived mechanisms which only serve to make transition cost recovery more confusing, and more importantly, we ensure that the transition cost recovery process can proceed expeditiously. We agree with ORA that proper accounting is essential so that utilities are required to recover all going forward costs from market revenues, to the extent lawful. We note that under Edison's approach, had its proposed 150 basis point mechanism been adopted, the utility would have greatly benefited because it would have recovered all coal and coal transportation contract costs from the transition cost balancing account before any revenue crediting mechanism was applied, including the 150 basis point earnback.

We discuss PG&E's geothermal contracts in Section 16.

14. Transition Costs and Power Purchase Contracts with QFs

PU Code § 367 affirms the Preferred Policy Decision's finding that the utilities are authorized to collect the ongoing transition costs resulting from the difference between contract prices with QFs and the Power Exchange market clearing price. In addition, transition cost recovery for QF-related costs continues for the duration of the contract and is not limited by the rate freeze period. While we find that such costs are eligible for recovery, we need not approve the forecasts of the costs included in the various utility filings. Transition cost recovery will be based on actual costs incurred compared to the Power Exchange revenues resulting from the market-clearing price.

PG&E recommends including costs related to QF contract litigation, settlements, and administration when comparing contract costs with market revenues. PG&E believes that this is legitimate, because these costs are in effect part of the cost PG&E pays for energy and capacity under these power purchase agreements. PG&E also contends that the Commission has issued contract administration guidelines that require the utilities to aggressively administer these contracts in order to control costs and protect ratepayers. Edison also included these costs in its assessment of QF contract costs.

ORA recommends that reasonableness reviews of the utilities' QF contract management continue to occur annually, but in the annual transition cost proceedings, rather than in the ECAC proceedings. ORA believes that it is essential that the utilities manage these contracts in a prudent manner. SDG&E contends that there is no reason for such a review in the transition cost proceedings, because we have expressed our intent to review this matter for SDG&E on an interim basis in D.97-07-064. SDG&E recommends that the purpose of the annual review regarding both QF and interutility contracts should be limited to an audit of costs, rather than a general reasonableness review, because it believes that this limited review should occur in the distribution PBR proceedings. Enron recommends that we consider requiring the utilities to forecast the annual QF stranded costs and interutility contract costs over the anticipated contract lives.

For PG&E, the auditors question all non-standard contracts, because they were unable to verify that they have been approved by the Commission. The auditors also recommend that any contracts included in the forecast of transition costs and involved in litigation should be considered questionable costs, since resolution of these issues may either increase or decrease projected costs. In addition, the auditors questioned contracts that do not conform with insurance verification requirements and contracts with QFs on probation for not meeting their contractual firm capacity requirements. The auditors presented similar concerns for Edison.

For each of the utilities, the auditors recommend that since transition costs associated with QF contracts depend on actual costs, a verification of these costs will be required, either in the ECAC or the annual transition cost proceedings.

Both AB 1890 and the Preferred Policy Decision state that the actual above-market costs of QF contracts are eligible for transition cost treatment. No forecast of the actual amount is necessary at this time. We will require that the utilities establish placeholders in their final balancing account tariffs to account for these costs when they are incurred. We accept Edison's and PG&E's responses to the audit report, regarding the questioned QF contract costs. No adjustments to these estimated costs are necessary, given that recovery of QF contract costs will be based on amounts actually incurred, rather than the estimated amounts. Costs related to Commission-approved contracts to settle issues associated with the BRPU are also eligible for transition cost treatment, pursuant to § 367(a)(3), although no amount need be forecast at this time. These costs are the focus of other proceedings. The utilities should establish placeholders in the transition cost balancing account to account for these costs, when and if they are approved.

SDG&E is currently under a Generation and Dispatch mechanism, which has eliminated the need for many aspects of traditional ECAC reasonableness reviews, including QF contract terms, because the contracts are standard offers or approved non-standard contracts. This mechanism will remain in place, with certain modifications, until the end of 1997. In D.97-07-064, we determined that reasonableness reviews for QF contract administration were appropriate and should take place "according to existing rate case processing procedures, as those procedures may be modified from time to time." (D.97-07-064, mimeo. at p. 15.) We have previously determined that "[t]he utility will retain its obligation to administer its QF contracts in the best interests of its customers and in a manner that maximizes systemwide benefits and minimizes transition cost accrual." (Preferred Policy Decision, mimeo. at p. 130.)

Consistent with D.97-07-042 and a joint ruling issued on June 25, 1997, by the assigned Commissioner and ALJ, generation PBRs will not be adopted prior to the beginning of the transition period. In the absence of generation PBRs, costs associated with QF and interutility contracts should continue to undergo reasonableness reviews, and these reviews should be undertaken as part of the annual transition cost proceedings, to the extent that such reviews are not eliminated by standard offers and approved contracts. Annual reviews will include a review of contract administration and litigation costs.

In D.96-04-034, which modified D.95-12-051, we provided that PG&E could recover the costs of QF litigation settlements and judgments if prudently incurred, but noted that reasonableness review of these costs was essential:

> "In future reasonableness reviews of settlement and judgment costs, we intend to inspect carefully the sources of the costs. If a settlement or judgment flows from the terms of a QF contract approved by the Commission, we may find that ratepayer support of associated payments is fair and reasonable. On the other hand, if a settlement or judgment is the result of imprudent contract administration by PG&E or in some way compensates a fuel or energy supplier for PG&E actions not approved by the Commission, then we may deny ratepayer support. In particular, judgments in tort actions – which generally exclude contract disputes – should not be recovered from ratepayers." (D.96-04-034, mimeo. at p. 3.)

This same rationale should apply to the litigation costs and QF administration costs for all utilities. We order this verification and showing to occur in the annual transition cost proceeding. This approach will allow us to transition out of the traditional ECAC proceedings. We make no findings at this time regarding the QF shareholder incentive mechanism, nor regarding QF contract restructurings and buyouts, which are being addressed in a separate proceeding.

15. Transition Costs and Interutility Contracts

PG&E, Edison, and SDG&E have various purchased power contracts with other utilities, irrigation districts, or water agencies. Similar to the treatment of QF contracts, both AB 1890 and the Preferred Policy Decision provided for the recovery of the difference between actual payments under those contracts and the cost of comparable energy purchases from the Power Exchange. Again, we emphasize that it is this difference that will be booked to the transition cost balancing account, not the forecast costs. Any revenues received from interutility sales contracts offset the transition costs. These costs will be reviewed in the annual transition cost proceeding.

ORA has agreed that PG&E's discretion in managing its eight purchased power contracts is minimal and therefore recommends that the review of these contract costs should be a simple audit of how the transition cost credit is calculated. ORA encourages SDG&E to renegotiate its two purchased power contracts and that the annual transition cost proceeding should be used to review the administration of these contracts. We concur and order such review to occur in the annual transition cost proceedings.

Edison has entered into 17 interutility power contracts, with prices that may be higher or lower than the market price. Transition costs or credits arising from these contracts are determined by comparing the costs associated with each contract to the corresponding market value of an equivalent amount of energy. In the case of energy exchange, transition costs are determined by comparing Edison's avoided cost and the contract price associated with energy takes and return. The actual transition costs associated with these contracts will be evaluated in the annual transition cost proceeding. Edison has agreed to various audit adjustments of its estimated costs, which relate to reclassifications and revised estimates. Edison objects to ORA's recommendation that the Commission should review purchases to ensure that purchases are maximized when incremental costs are lower than the Power Exchange price and minimized when incremental costs are greater than Power Exchange price. In contrast, Edison recommends that ORA's review process be amended to include verification of benefits associated with interutility purchases, exchanges, or sales made through the Power Exchange. We will review both costs and benefits of such purchases, sales, and exchanges in the annual transition cost proceedings and will review each utility's showing carefully in this regard, consistent with our desire to ensure that transition costs are minimized to the extent possible.

16. Hydroelectric and Geothermal Transition Costs

In addition to its fossil-fired generation assets, PG&E owns both hydroelectric and geothermal generating assets. Edison owns hydroelectric assets, but no geothermal assets. SDG&E owns only fossil assets. Section 367(b) states that for all assets subject to market valuation, such valuation must occur by December 31, 2001. Because the Preferred Policy Decision required that hydroelectric assets and geothermal assets be retained by the utilities (Preferred Policy Decision, mimeo. at p. 135), and AB 1890 was silent on this issue, there has been some dispute as to whether hydroelectric and geothermal assets are indeed subject to § 367(b). Parties have also raised issues regarding the correct rate of return to apply to these assets and whether the depreciation of these assets should be accelerated or not.

The generation PBR proceeding (A.96-07-009 *et al.*) has been modified to defer development of PBR mechanisms and instead will determine 1998 revenue requirements for PG&E's hydroelectric and geothermal generating units and Edison's hydroelectric units. In this transition cost proceeding, we address the following issues associated with hydroelectric and geothermal assets: the net book value as of December 1, 1995, the applicable rate of return, whether depreciation should be accelerated or not, and how to properly track hydroelectric and geothermal costs and revenues in the transition cost balancing account.

Certain issues associated with the ratemaking treatment of hydroelectric plants that are categorized as must-run by FERC and the reasonableness of pumped storage plant costs will be more fully co:'sidered in A.96-07-009 *et al.*

16.1. PG&E

PG&E states that it plans to market value all of its non-nuclear generation assets (RT:1281), including its hydroelectric and geothermal facilities. PG&E believes that the reduced rate of return applies only to uneconomic assets. PG&E asserts that when an individual hydroelectric or geothermal asset is identified as having a book value greater than its market value, depreciation on that asset should be accelerated and the rate of return should then be the reduced rate of return. However, PG&E contends that if recovery of the asset is not accelerated, it should continue to earn at the authorized rate of return. PG&E states that it intends to accelerate depreciation of these assets so that book value equals expected market value, and intends to modify the forecast of net salvage used in determining the proper levels of accelerated depreciation as better forecasts become available.

PG&E proposes to debit that the entire hydroelectric and geothermal revenue requirement to the transition cost balancing account. Any ISO or Power Exchange revenues earned by these plants would then be credited to the balancing account. Thus, any net credit would be used to offset other transition costs and any net debit would be recovered through the CTC or other offsets. PG&E recommends establishing the revenue requirement for hydroelectric and geothermal assets in A.96-07-009 *et al.*, but addressing the recovery of those costs in this proceeding.

While PG&E acknowledges that the Preferred Policy Decision provides that surplus revenues from hydroelectric and geothermal assets will be credited to offset transition costs, PG&E contends the Commission has overlooked the possibility that some of these plants could, in the short run, result in a net debit to the transition cost balancing account; e.g., in the event of a dry year. While PG&E expects that these plants as a whole will be economic over the long run, to the extent that timing issues result in a net debit (that is, costs exceed revenues), PG&E asserts that we should allow recovery of these uneconomic costs via the transition cost balancing account.

PG&E explains that until the end of 1992, its hydroelectric relicensing costs were recorded in rate base as these costs were incurred. In D.92-12-057, we determined that these costs should be treated as CWIP, earning an Allowance for Funds Used During Construction (AFUDC) until the new licenses were granted by FERC, at which time the relicensing costs would be transferred to rate base. (47 CPUC2d, 143, 218.) PG&E now requests that we reverse this approach and transfer the December 31, 1997 CWIP balance related to hydroelectric relicensing costs to rate base effective January 1, 1998 for transition cost recovery. PG&E would accept TURN's alternate approach in which the relicensing costs would continue to accrue AFUDC until the time of market valuation and then be recovered in the market valuation process. PG&E explains that the value of a hydroelectric plant is in its license and that the relicensing process is lengthy and subject to certain requirements at precise times. If relicensing efforts were stopped, the value of the hydroelectric facilities would be only the net book value of the historical costs; alternatively, PG&E recommends that if shareholders continue the relicensing efforts, the value of the licensed plant above book value should accrue to shareholders.

16.2. Edison

Edison recommends that hydroelectric generation should earn the full rate of return prior to market valuation. Edison defines costs recoverable through the transition cost balancing account as the difference between the authorized revenue requirement and market revenues. While Edison was unsure initially whether or when it would seek to market value its hydroelectric assets, Edison now agrees that market valuation should occur. (Exhibit 99.)

Edison explicitly states that its agreement to market value its hydroelectric assets is predicated on continuing to earn a full rate of return on those assets until they are market valued. In A.96-07-009 *et al.*, Edison has proposed to derive its hydroelectric revenue requirement from its test year 1995 GRC decision, with certain adjustments.

Edison states that because its development of its hydroelectric revenue requirement is based on 1995 test year levels, it is assuming additional risks in the operation of these assets, which requires a full rate of return, rather than the reduced transition cost rate of return.

Edison states that it does not plan to accelerate recovery of its hydroelectric sunk costs prior to market valuation and argues that there is no reason to reduce the return to reflect the reduced risk associated with accelerated recovery until it occurs.

Edison disputes FEA's and ORA's conclusion that the Preferred Policy Decision limits the transition cost calculation to net credits resulting from hydroelectric assets and believes that such a conclusion would violate § 67(b), which requires the netting of all above-market and below-market assets.

The auditors explain that Edison removed its hydroelectric sunk costs from Edison's Statement of Eligible Transition Costs, which also identified $525.7 million in future hydroelectric PBR costs, as of January , 1998. When the auditors raised concerns regarding double counting, Edison elected to remove the sunk cost amounts. The auditors prefer that Edison remove its hydroelectric PBR costs from its statement of eligible transition costs, because these amounts are based on speculative estimates that cannot be evaluated.

16.3. ORA

Contrary to PG&E and Edison's proposal that any difference between the frozen revenue requirement and market revenues be credited or debited to the transition cost balancing account, ORA asserts that the Preferred Policy Decision provides only for offsets to the transition cost recovery when the hydroelectric Power Exchange revenues exceed the revenue requirement. ORA believes that allowing debits to flow through the transition cost balancing account could make it difficult to limit transition cost recovery of operating costs and suggests that allowing the utilities to recover costs through transition cost recovery could lead to manipulation of the market, because utilities would have an incentive to bid low for their hydroelectric generation.

ORA fears that this bidding behavior could impact the development of the competitive market by preventing market entry, prolonging transition cost recovery, and driving out competitors.

ORA recommends that hydroelectric and geothermal assets should not receive accelerated amortization prior to market valuation because they are likely to have market values exceeding book values. ORA recommends accepting the net book values confirmed by the audit report, provided that capital additions prior to December 1, 1995 are reviewed and audited. Furthermore, ORA recommends that the issue of how differences between an established revenue requirement and market revenues should be tracked in the transition cost balancing account should be determined in A.96-07-009 *et al.*, because that proceeding contains the most comprehensive discussion of ratemaking issues.

ORA agrees that § 367(b) requires market valuation of all assets and recommends that such market valuation occur soon so that any value in excess of net book value can be used effectively to offset transition costs.

ORA generally agrees with PG&E's proposals regarding geothermal assets, but recommends that geothermal steam costs be subject to reasonableness review in either the annual transition cost proceeding or the Revenue Adjustment Proceeding. ORA recommends booking a credit to the transition cost balancing account only if Power Exchange revenues exceed the applicable costs, including non-accelerated depreciation of capital costs for non-must-run units. For must-run units, all costs should be negotiated with the ISO and would not impact transition costs.

16.4. TURN

TURN recommends denying authorization to accelerate the recovery of sunk costs of hydroelectric generation facilities, with two exceptions. TURN asserts that because these assets are likely to have a market value above book value and are likely to generate electricity at costs less than market prices, these assets are the "crown jewels" of the utilities' portfolios. Since hydroelectric assets have a market value above book, there should be no need to accelerate depreciation; indeed, TURN recommends that doing so would violate the principles articulated in D.97-06-60. TURN maintains that market valuation can occur in compliance with § 67(b), without triggering accelerated depreciation.

TURN recommends that pumped storage facilities, which are likely to have book values in excess of market values, and other individual plants sold at less than book value should be allowed transition cost treatment. TURN recommends that past hydroelectric relicensing costs should be recovered consistent with the ratemaking treatment afforded the underlying plant. If the hydroelectric plant is market valued during the transition period, the relicensing costs should be recovered as an offset to the market value. If the Commission determines that these assets should continue to be owned by the utilities, TURN states that it could support Edison's proposal to accrue AFUDC on these costs and recover them in the PBR mechanism.[22] TURN recommends that no accelerated recovery be afforded past relicensing costs with the exception of those plants already sold or those that are sold before 2001. TURN further recommends that hydroelectric and geothermal assets should earn the lower rate of return if market valuation is proposed for these assets. The full rate of return should apply if the utility holds them in regulated service and market values them on an annual basis through credits against other rate components after 2001.

16.5. FEA

FEA recommends that to the extent hydroelectric and geothermal assets are retained by the utilities, only the surplus of hydroelectric revenues over associated costs should be permitted to reduce transition costs; any deficit should not be permitted to increase transition costs. FEA supports the auditors' proposed adjustment to remove Edison's $525.7 million in hydroelectric PBR costs from the transition cost balancing account.

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[22] In its July 1, 1997 compliance filing in A.96-07-009 *et al.*, Edison states that it will commit to recover these costs out of the frozen level of currently authorized revenues and that any hydroelectric relicensing costs should be recovered through the market valuation process.

16.6. CIU

CIU contends that market valuation is required for all facilities to calculate the complete transition cost formula and is not a matter of utility choice. CIU agrees that accelerated depreciation is not appropriate for hydroelectric and geothermal assets prior to market valuation. CIU recommends waiting until after the new competitive market begins operation to consider the market valuation of hydroelectric assets, although CIU recognizes that valuation before the end of the transition period is important.

16.7. Discussion

We agree that careful treatment regarding the hydroelectric and geothermal assets is in order. We accept the auditors' determination of the net book value as of December 31, 1995 as the starting point for determining whether assets will ultimately be economic or uneconomic.

AB 1890 is silent regarding the treatment of these particular categories of assets, although market valuation is required "for those assets subject to valuation." in § 367(b). Section 367 requires that we determine the cost categories that may become uneconomic as a result of the competitive generation market. While we are not convinced that hydroelectric and geothermal assets, with the possible exception of pumped storage facilities, are likely to be uneconomic, we believe that ratepayers will benefit by ensuring that these assets earn the reduced rate of return and that excess revenues are credited to offset transition costs. We find that it is appropriate to include the amortization of any current costs of hydroelectric and geothermal assets in the transition cost balancing account. PG&E will recover geothermal steam contract costs in the revenue requirements set in A.96-07-009 et al.

A separate proceeding is underway to determine the revenue requirements associated with these assets. This revenue requirement will be developed based on a cost-of-service approach, and will include amounts to offset fixed costs, nonfuel variable costs, depreciation, taxes, and a return on investment. Calculations of the revenue requirement should begin with the net book value adopted in these proceedings.

Revenues earned through the Power Exchange and ISO for hydroelectric and geothermal assets should be tracked in a memorandum account and compared to the revenue requirements established for these assets in A.96-07-009 *et al.* Market revenues in excess of revenue requirements should be credited to the transition cost balancing account on an annual basis. Similar to the memorandum accounts established for the fossil must-run and non-must-run plants, any excess revenues accruing in a particular month will earn the reduced transition cost rate of return, rather than the commercial paper rate. Applying the reduced rate of return to these revenues is appropriate because this higher interest rate compensates ratepayers for carrying costs associated with transition costs that would otherwise have been reduced through monthly postings. No interest rate or rate of return will be applied to any debit balances in that memorandum account. This approach is consistent with ensuring that transition cost recovery occurs as expeditiously as possible. Because these assets are afforded transition cost treatment, the reduced rate of return should be earned.

Pumped storage plants are also likely to be uneconomic in the new competitive generation market. We will therefore allow recovery of costs associated with pumped storage assets in the transition cost balancing account; however, complete ratemaking determinations cannot be made pending the outcome of the treatment of must-run and non-must-run hydroelectric plants, including pumped storage assets, in A.96-07-009 *et al.* Once we have issued our decision in that proceeding, we will allow PG&E and Edison to modify their balancing account tariffs to more fully delineate the balancing account treatment of pumped storage facilities.

Section 367(b) requires basing the determination of uneconomic costs on a comparison of market value to book value for utility-owned generation assets. The Legislature has provided explicit affirmation of the benefits of competition, as well as directions that transition cost recovery should be orderly, expeditious and that the transition from regulated status to unregulated status must occur through means of Commission-approved market valuations. We conclude that hydroelectric and geothermal assets are subject to market valuation and that we must approve all market valuation mechanisms, including the timing of these mechanisms. Market valuation must occur well before 2001 so that the netting process can occur as required by § 367(b).

Past relicensing costs should be accounted for in market valuation process, as PG&E, Edison, and TURN now agree. These amounts will continue to be recorded in CWIP and accrue AFUDC. This approach is consistent with our preference to use market mechanisms to determine transition cost recovery.

17. Regulatory Assets, Liabilities and Transition Obligations and Balancing Accounts

In the Preferred Policy Decision, the Commission recognized that regulatory assets and liabilities have arisen from various deferred costs and outstanding balancing account balances which each utility has accrued under traditional cost-of-service regulation. Regulatory assets results in the ratepayers owing money to the utility; regulatory liabilities result in the utility owing money to ratepayers. Regulatory assets and liabilities are defined in the FERC Uniform System of Accounts as follows:

> "Regulatory Assets and Liabilities are assets and liabilities that result from rate actions of regulatory agencies. Regulatory assets and liabilities arise from specific revenues, expenses, gains, or losses that would have been included in net income determination in one period under the general requirements of the Uniform system of Accounts but for it being probable:
>
> "A. that such items will be included in a different period(s) for purposes of developing the rates the utility is authorized to charge for its utility services; or
>
> "B. in the case of regulatory liabilities, that refunds to customers, not provided for in other accounts will be required." (18 CFR, Part 101, p. 259, April 1, 1996.)

As we explained in Section 6.5, we find that both regulatory obligations and contractual obligations are eligible for transition cost recovery, in conformance with § 367. However, we will review each claim for transition cost recovery in this category to determine whether such assets and obligations are generation-related, unavoidable, and uneconomic.

In D.92-12-015, we accepted the following definition in terms of post-retirement benefits other than pensions (PBOPs) and the applicability of Statement of Financial Account Standards (SFAS) 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 incurred cost rather than to provide for expected levels of similar future costs." (46 CPUC2d 499, 536.)

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

It is useful to put the ratemaking approach to regulatory assets in perspective as we proceed. First, it is important to distinguish between "accrual" accounting and the "pay as you go" method. Accrual accounting occurs when the utility recognizes the costs of benefits as they are earned or attributed to an employee, as services are provided. For financial reporting purposes, utilities account for PBOPS, pensions, workers' compensation, and long-term disability benefits on an accrual basis (i.e., an actuary determines the total expected obligation for benefits owned to employees and the utility recognizes a portion of the accrual each year as the employee continues to provide service). In contrast, under "pay as you go" accounting, a utility recognizes an employee benefit cost when it actually pays such a benefit to the employee.

ORA explains that there is no disagreement regarding financial reporting of regulatory assets, which is a management decision. ORA states that this Commission must determine whether these costs should be treated similarly for ratemaking purposes. In general, ORA believes that benefit obligations associated with future generation-related activities of the utilities after divestiture can be funded from future market revenues. In other words, ORA believes that these obligations should be recoverable through pre-1998 ratepayer funding of accruals towards active employees, because these obligations will be eliminated or decreased due to divestiture.

ORA suggests that several issues must be resolved before we determine that particular regulatory assets are eligible for transition cost recovery. ORA believes that the record is insufficient to answer these key questions and recommends workshops to determine: 1) whether regulatory assets should be eligible for recovery at all, i.e., by AB 1890 criteria or by previous Commission decision; 2) when it is appropriate for the utilities to establish a regulatory asset; 3) whether particular regulatory assets are related to historic operations or whether these assets include going forward costs; 4) whether such costs could be mitigated in some way and whether transition cost recovery may encroach upon that mitigation; and 5) if found eligible, what portion of these regulatory assets should be subject to transition cost recovery.

As previously discussed, EPUC and CIU contend that regulatory assets associated with fossil plants are not eligible for recovery. This narrow approach is inconsistent with the law, and we find that generation-related regulatory assets are eligible for recovery as a cost category. We will consider the disputed issues of the various regulatory assets in question. As a threshold matter, we are addressing the eligibility of various employee benefits for recovery in the transition cost balancing account that have been earned or attributed to employee service rendered <u>prior</u> to January 1, 1998 for generation employees. <u>After</u> January 1, 1998, these costs must be included in current operating costs and recovered from market revenues.

In general, ORA also recommends denying regulatory assets for transition cost recovery. ORA states that this is true because either the utilities did not file to have past benefit obligations recovered in future time periods or the utilities are not in compliance with D.92-12-015, in terms of PBOPs. ORA's position is that divestiture and subsequent termination of maintenance contracts will lead to reduced payroll expenses and lower PBOP expenses than were assumed in the actuarial calculations. PG&E asserts that amortization should begin on January 1, 1998, a position which PG&E states is consistent with the requirements of D.97-06-060. ORA also recommends establishing accounting safeguards to prohibit non-generation operations from subsidizing generation and the diversion of ratepayer funding of employee benefits to non-pension and benefits usages.

ORA proposes that all other regulatory assets be eligible for transition cost recovery, with the following conditions. Regulatory assets related to deferred taxes should be treated according to the provisions of the joint recommendation contained in Exhibit 101. In addition, ORA recommends that certain PG&E ECAC balancing account amounts related to disallowances should be refunded to customers, rather than being credited to the transition cost balancing account.

17.1. Workers' Compensation

PG&E proposes to recover the workers' compensation regulatory asset in the transition cost balancing account, based on the December 31, 1997 balance, to be amortized over the 48-month transition period. PG&E explains that if an employee has a claim under workers' compensation, then PG&E is legally obligated to provide the required level of benefits. PG&E believes that the proper rate of return to apply to this balance is PG&E's discount rate at December 31, 1997. Workers' compensation costs are recognized on an accrual basis for financial reporting purposes, but are recovered on a pay-as-you-go basis for ratemaking. Assuming no new entrants are afforded workers' compensation benefits, the differences resulting from these two accounting methods would zero out over time under traditional ratemaking, because the regulatory asset is reduced as rates are received each year. PG&E contends that there is a reasonable expectation that it would recover all of its workers' compensation accruals in rates over time. PG&E plans to avoid any double counting, an issue that concerns TURN, by reducing the current cost revenue requirement for any costs provided by recovery of this regulatory asset. These costs would be subject to review in the annual transition cost proceeding.

Edison has identified a generic regulatory asset for post-employment benefits, including workers' compensation and long-term disability. This proposal is discussed in Section 17.2, Long-term Disability.

ORA states that because PG&E funds workers' compensation obligations on a pay-as-you-go basis, PG&E is collecting current costs through rates; i.e., the fact that PG&E's workers' compensation obligations are recognized on its financial statements in accordance with SFAS 112 (Employers Accounting for Postemployment benefits) is irrelevant. ORA concurs with TURN's objection to transition cost recovery of these costs because it is impossible to distinguish between pre-1998 and post-1998 liabilities.

TURN contends that this regulatory asset is not eligible for transition cost recovery, because PG&E has not borne its burden of proving the appropriate level of the costs to be recovered, has not demonstrated that going forward costs are excluded from recovery, and has not established that double counting will not occur. TURN recommends that if recovery is allowed, no rate of return should apply.

17.1.1. Discussion

In D.95-12-055, we determined that PG&E's requested increase in revenue requirements for workers' compensation and other casualty payments would be mitigated to some extent by employee reductions, and we reduced the adopted revenue requirements. These costs are recovered on a pay-as-you go basis; therefore, the rates include costs that would also have been included in the actuarial calculation for post-1998 obligations of the workers' compensation regulatory asset. This is quite different from the methodology PG&E uses to address its long-term disability obligation. In this case, PG&E has not adequately distinguished costs which represent past obligations from costs which represent future obligations. The Commission has never established a regulatory asset for workers' compensation obligations. Because rates are frozen throughout the transition period, we expect that the forecasted revenue requirement will be adequate to cover PG&E's generation-related workers' compensation obligation related to pre-1998 claims. There is significant potential for double recovery, as well as a mingling of pre-1998 and post-1998 costs that is inappropriate in the new generation market; therefore, we will exclude PG&E's workers' compensation regulatory asset from transition cost recovery at this time.

PG&E may demonstrate in the annual transition cost proceeding that its actual payments in 1996 and 1997 for workers' compensation claims exceed what had been previously approved in rates for generation employees.

17.2. Long-term Disability

PG&E and Edison propose to recover the long-term disability regulatory asset in the transition cost balancing account, based on the December 31, 1997 balance, to be amortized over the 48-month transition period. Again, PG&E explains that if an employee has a legitimate long-term disability claim, the utility is legally obligated to provide the required benefits. Long-term disability costs are recognized on an accrual basis for financial reporting purposes and are recovered on a funding/accrual basis for ratemaking. Prior to its 1996 GRC, PG&E collected these expenses on a pay-as-you-go basis. In D.95-12-055, we authorized a $17 million increase in PG&E's revenue requirements to fund the accounting change for long-term disability obligations from a cash basis to an accrual basis.

PG&E contends that authorized rate recovery for long-term disability costs compared to projected levels of future expenses are not equal and a regulatory asset has been created to account for these differences. Under traditional ratemaking, PG&E expected that it would eventually recover these generation-related costs recorded on an accrual basis prior to January 1, 1998 relating to past employee service. PG&E believes that the proper rate of return to apply to this balance is PG&E's discount rate at December 31, 1997. PG&E recommends that it is the unfunded obligation, not the initial unamortized obligation, as of December 31, 1997, which should be amortized in the transition cost balancing account, because the long-term disability obligation is revalued each year.

ORA believes that PG&E's request should be denied, because this amount reflects the difference between what was authorized in D.95-12-055 and what the utilities have booked or will book in the future. ORA believes that this obligation is applies to active employees and will be eliminated as divestiture occurs. The past funding of active employees who will leave the utilities' employment should provide sufficient funding for obligations resulting from claims of remaining employees.

TURN recommends recovering PG&E's long-term disability obligation as a transition cost, because TURN agrees with PG&E's proposed treatment of this obligation (i.e., establish a trust fund for long-term disability costs, set up an initial obligation, and to change to the accrual basis for cost recovery). TURN does not agree that the long-term disability obligation should be revalued each year, and states that this amount must be fixed and amortized as of the time the obligation was identified to prevent any inappropriate inclusion of going-forward costs in the regulatory asset collected through transition cost recovery. TURN recommends that the initial obligation should be that established in PG&E's 1996 GRC. TURN believes that there should be no rate of return applied to this asset and that there should be a rate base offset with normalization of deferred taxes, if these costs are not immediately deposited in a trust.

Edison and TURN now agree on Edison's approach to post-employment benefits and have agreed to the following criteria: 1) Edison requests recovery of costs associated with post-employment benefits for liability associated with claims made pre-1998 and plans to amortize the amount as of December 31, 1997 over the 48-month amortization period as established in D.97-06-060; 2) Edison is not requesting a rate of return on regulatory assets associated with post-employment benefits; and 3) the regulatory asset associated with post-employment benefits associated with employees of non-must-run fossil stations made subsequent to December 31, 1997 will be considered going forward costs rather than unavoidable costs and is proposed to be reflected in the operation of the 150 basis point incentive computation.

17.2.1. Discussion

Because we have approved accrual accounting treatment for this obligation and we can establish a cut-off point for going forward costs, the long-term disability obligation is eligible for transition cost recovery. For Edison, we adopt the post-employment benefits ratemaking treatment jointly proposed by Edison and TURN: 1) benefits will follow labor dollars and the rate recovery depends on which business unit the labor is associated with, i.e., for generation-related nuclear obligations, recovery will occur through SONGS ICIP and Palo Verde incremental cost mechanisms; for fossil assets, recovery will occur through the transition cost balancing account regulatory asset subaccount. For hydroelectric assets, TURN and Edison have jointly proposed that recovery occur through the hydroelectric PBR. The generation PBR has been deferred; however, the Commission is establishing a revenue requirement for hydroelectric assets. Transition cost recovery is authorized only for the regulatory asset associated with claims made prior to 1998. Edison shall not use the pay-as-you-go methodology and shall recover the amount recorded as of December 31, 1997, which will then be amortized ratably over the 48-month transition period. No rate of return will be applied to this regulatory asset subaccount, nor will any of the regulatory asset balances earn any interest, consistent with our prior ratemaking approach to these assets.

In D.95-12-055, we adopted the Division of Ratepayer Advocates' (ORA's predecessor) recommendations regarding long-term disability obligations. Prior to collecting any funds for this purpose, PG&E was required to establish a trust which provides that PG&E may not divert any trust assets to uses other than post-employment benefits. In that decision, we also determined that "[u]ltimately, PG&E shall refund any amounts included in rates that are not contributed to the fund." (D.95-12-055, mimeo. at p. 29.) PG&E's post-employment benefits should be accounted for similarly to Edison's. The initial obligation as established in the 1996 GRC decision should be amortized over the 48-month transition period. This amount equates to the level established by actuarial assumptions as reflected in current rates and is an approach consistent with § 367. We see no need to revalue this amount, which has the potential of increasing this obligation. No rate of return or interest shall be applied to this regulatory asset subaccount. These costs shall be subject to review in the annual transition cost proceedings.

17.3. Post-Retirement Benefits Other than Pensions (PBOPs) and PBOPs Transition Obligation

The PBOP regulatory asset represents estimated costs for medical and life insurance benefits accrued since 1993, which are not yet recovered in rates. PG&E and SDG&E propose to recover the PBOP regulatory asset in the transition cost balancing account, based on the December 31, 1997 balance, to be amortized over the 48-month transition period. SDG&E explains that this asset represents costs obligated prior to December 20, 1995, all of which were approved for recovery in SDG&E's 1993 GRC. PG&E recommends that amortization of the amount as of December 31, 1997 should be spread over the four-year transition period and recommends that the proper rate of return to apply to the unamortized balance is PG&E's discount rate at December 31, 1997.

The PBOP transition obligation represents the cost of medical and life insurance benefits attributed to employee service which occurred prior to 1993. The transition obligation was adopted in D.95-12-015 and the utilities were authorized to amortize its balance over 20 years. This amortization amount has been included in the revenue requirements for each utility. There will be 15 years left on the transition obligation amortization schedule as of January 1, 1998. PG&E, Edison, and SDG&E propose that the balance in PBOP Transition Obligations as of January 1, 1998 (calculated according to the Commission-approved 20 year amortization schedule) be recovered in the transition cost balancing account over the 48-month transition period.

Edison points out that if the amount collected in rates and funded is not completely tax-deductible, it would have to be grossed-up for income taxes. Edison has estimated the amount attributable to non-nuclear generation by calculating the ratio of non-nuclear to total 1995 dollars and then applying that ratio to the actuarially determined transition benefit obligation as of 1995; however, Edison explain that amounts actually recovered will vary. D.97-06-060 requires that regulatory assets be amortized over the 48-month transition period, and because § 367(d) requires that transition costs be adjusted throughout the transition period, the transition benefit obligation must be updated annually.

Consistent with its overall recommendations on these regulatory assets, ORA insists that PBOPs regulatory assets and transition obligations are not eligible for transition cost recovery. ORA continues to recommend that the obligation associated with this benefit will be reduced or eliminated as the work force is reduced; hence, the past funding of active employees who leave the utility's employment should provide sufficient funding for future obligations of remaining employees. ORA is also concerned that the utilities would receive funding in excess of what can be contributed to the trusts on a tax-deductible basis.

TURN recommends that a uniform policy be established for PBOPs for all three utilities: 1) all eligible PBOP amounts must be collected in transition costs by the end of 2001; 2) any uncollected PBOP amounts or unamortized PBOP transition obligation should not earn interest, consistent with the provisions of D.92-12-015; 3) any PBOP amounts not deposited in the trust fund should be a rate base offset net of deferred taxes; and 4) if any utility reduces its post-retirement benefits in the future, which in turn reduces the actuarial basis of its PBOP transition obligation, any excess dollars collected for generation should be refunded to ratepayers.

TURN recommends rejecting PG&E's request to earn interest on PBOP costs and Edison's request to collect generation-related PBOPs after 2001. TURN states that PG&E has accrued a regulatory asset related to PBOPs because of a difference in applying the correct discount rate. TURN explains that PG&E used a different discount rate for evaluating its PBOPs obligation than the discount rate of 9% adopted in D.95-12-055. TURN believes that no rate of return should be applied to this asset and that there should be a rate base offset with normalization of deferred taxes if these costs are not immediately deposited in a trust.

TURN recommends that the utilities should be eligible to collect the generation-related PBOPs transition obligation as of December 31, 1997, because these transition obligations were incurred as a result of past service by generation employees. TURN maintains that to the extent that Edison wants transition cost recovery for PBOPs, it should be required to recover its generation-related transition obligation by the end of the transition period and should not be allowed to defer generation-related transition costs for recovery in non-generation rates, which TURN asserts is prohibited by § 368(a). TURN agrees with the amortization approach, but recommends that no rate of return be applied, consistent with D.92-12-015. TURN also recommends a rate base offset, which will produce credits to the transition cost balancing account, if this obligation is not immediately deposited in the trust.

CIU thinks that Edison should not claim PBOPs related to Mohave employees, because this obligation is related to the coal mine's employees, rather than Edison's employees.

17.3.1. Discussion

It is helpful to understand the historical framework underlying ratemaking treatment of PBOPs and the PBOP transition obligation. The Financial Accounting Standards Board (FASB) has defined PBOPs as those benefits other than pensions that employees would receive upon their retirement from the active work force, including medical and dental care, life insurance, and legal services. The Commission opened I.90-07-037 in 1990 to determine the ratemaking impact of changing accounting for PBOPs from a cash to an accrual basis and to address the ramifications of SFAS 106. In D.91-07-006, we determined that the change from cash to accrual accounting for these obligations was reasonable and that the utilities should pre-fund PBOPs with tax-deductible trust plans prior to January 1993, the effective date of SFAS 106. We also established safeguards for these trusts. In D.92-12-015, we determined that PBOP costs consist of a service cost, an interest cost, the actual return on plant assets, and the amortization of the transition benefit obligation. We also found that the substantial increase in PBOP costs under accrual accounting was due primarily to the transition benefit obligation, which recognizes all PBOP benefit obligations at January 1, 1993 less any plan assets at that date. We determined that the transition benefit obligation should be amortized over 20 years, which would mitigate inter-generational inequities, and that water, energy, and telecommunication utilities should "recover their PBOP costs in rates to the extent that they are able to make tax-deductible contributions to tax-deductible plans" and should also establish a regulatory asset for ratemaking purposes which would reflect the annual differences between PBOP expense determined in accordance with SFAS 106 and the tax-deductible contributions recovered in rates. The decision also established that the PBOP regulatory assets would not be a component of rate base and therefore would not earn a rate of return.

We are not persuaded by ORA's arguments. These regulatory assets have been established with our authorization and fit the criteria established by § 367. The PBOP regulatory assets, including the PBOP transition obligation, are eligible for recovery through the transition cost balancing accounts and should be amortized ratably over the transition period, with no recovery beyond 2001. These amounts should be amortized based on the December 31, 1997 estimates, which represent actuarial determinations of past obligations, with no rate of return or interest applied to the unamortized balances. If post-retirement benefit plans are modified to reduce benefits during the transition period, which then reduces the actuarial basis of the transition obligations, these true-ups should be accounted for as credits to the transition cost balancing account. We agree with Edison that such adjustments should be made during the transition period only. For PG&E, it is reasonable to apply the discount rate of 9% adopted in D.95-12-055. If PG&E believes this discount rate was adopted in error, PG&E must file a petition for modification in the relevant proceeding. These accelerated amounts are to be placed in the appropriate trust funds for each utility; to the extent they are not so deposited, these amounts will be treated as a rate base offset with a corresponding credit to the transition cost balancing account.

Edison acknowledges that it does not yet have any obligations related to the Mohave coal mine employees for PBOP expenses. We will exclude these amounts from transition cost recovery at this time. We will not allow a tax gross-up to the extent these contributions to the trust are not tax-deductible. Instead, we adopt TURN's recommendation not to be contributed these dollars to the trusts until they are tax-deductible. Any money which is collected but not yet contributed then becomes a rate base offset, which is reduced by deferred taxes associated with the asset for the taxes due when the money is collected. This approach will address necessary tax requirements, but avoids imposing an additional cost on the ratepayers. This is an example of an approach which aligns both shareholders and ratepayers interests.

17.4. Pensions

Pensions can give rise to either a regulatory asset or liability and to a transition benefit obligation, similar to PBOPs. The utilities state that a regulatory asset or liability can arise with respect to pensions because of different methods for calculating the pension expense for ratemaking purposes and financial reporting purposes. SFAS 87 addresses accounting for pensions for financial reporting purposes. In D.88-03-072, we declined to adopt SFAS 87 for ratemaking purposes. This decision applied to telephone carriers, but has been broadly applied to energy utilities (e.g., D.89-12-057; D.91-12-076). In D.88-03-072, we determined that the aggregate cost method of accounting for pension expense was appropriate for ratemaking purposes. Under this method, the estimated total benefit due at retirement is forecasted and an amount is calculated to provide this benefit, discounted to net present value and spread over future years on a levelized basis. SFAS 87 proposed a unit credit method, based on the yearly pension costs of an employee (i.e., lower in the beginning of an employee's years of service and rising as the employee ages). We found that if the yearly benefits approach were adopted for pension expense, it would be inconsistent with other ratemaking policies and would result in a mismatch of the amount expensed for ratemaking purposes and the amount actually required to be contributed to the pension funds.

PG&E asserts that the regulatory asset or liability arises from the SFAS 87, which require a change from the cash basis to the accrual basis of accounting and allowed the transition adjustments to be amortized over several years. PG&E explains that based on accrual accounting, rather than cash accounting, a regulatory liability related to pensions is expected as of January 1, 1998, which it proposes to credit to the transition cost balancing account. PG&E observes that over time there would be no difference between accounting by SFAS 87 or by the aggregate cost method. PG&E maintains that because of electric restructuring, these differences cannot be evened out and these costs become equivalent to sunk costs. PG&E states that full recovery of the pension transition obligation (to address the change from cash basis to accrual basis) will not occur by the end of the restructuring transition period and this amount should therefore be recovered as a sunk cost. PG&E proposes to net the transition obligation with the regulatory liability and to credit the transition cost balancing account for this amount.

Edison proposes that either the debit or credit balance as of January 1, 1998 should flow through the transition cost balancing account over the 48-month amortization period. Edison explains that the difference between book and ratemaking pension expense created a regulatory liability of $1.8 million by year-end 1995, but Edison did not include this amount as an offset to transition costs because it expected that this amount would either zero out or revert to a *de minimus* regulatory asset balance by year-end 1997.

ORA believes that pensions and benefit obligations differ from other assets for which the utilities seek transition cost recovery, because rate base items have been reviewed for reasonableness, which ORA asserts is not the case for these regulatory assets. ORA maintains that there is not a straightforward relationship between past Commission decisions and particular amounts requested for transition cost recovery. ORA recommends that the generation-related obligations to retirees which remain with the utility can be funded without transition cost recovery and that many of these obligations will be eliminated with divestiture. ORA explains that pension obligations are governed under various sections of the Internal Revenue Code and the Employee Retiree Income Security Act, which require pension benefits to be funded as earned and to vest with the individual employee. Furthermore, because ratemaking is based on the tax-deductible contribution amounts, ORA contends that there is no basis for extending recovery beyond what has already been funded and the employees have earned.

TURN demonstrated that this liability has grown from $1.8 million to $4.7 million by year-end 1996. Edison agrees with TURN that any regulatory liability related to pension expense should be credited to the transition cost balancing account, but only if it receives symmetrical treatment for any similar debit balances. Subsequent to its rebuttal testimony, Edison discovered that this calculation had failed to account for the pension transition obligation, which is estimated to equal $5.6 million for non-nuclear generation pension expense. Edison proposes that this amount be netted with the regulatory liability and the difference as of December 31, 1997 (either liability or asset) should be amortized over the transition period. Edison thus proposes that the fossil-related pension transition obligation balance left to be amortized as of January 1, 1998 (calculated under the Commission-approved 17-year amortization schedule) should be recovered through transition costs over the 48-month period. SDG&E agrees that the regulatory asset should be amortized over the 48-month period.

For PG&E and Edison, TURN recommends that if the regulatory asset resulting from the transition obligation is offset by larger regulatory liabilities resulting from ratemaking pension costs exceeding financial reporting pension costs, the net regulatory liability balance as of January 1, 1998 should be credited to reduce transition costs. TURN assumes that any net regulatory asset is a result of amortizing the transition obligation and TURN recommends that this asset should be reduced to zero for transition cost recovery purposes. TURN asserts that the utilities' pension funds have significant amounts of excess reserves relative to the amounts needed to pay the claims of future retirees, even after repaying the transition obligation; therefore, no additional recovery should be available through transition costs. TURN explains that PG&E has been able to pay this transition obligation at no expense to the ratepayers because the pension fund has been a source of income to PG&E. TURN expects that this scenario will continue, at least through the transition period.

TURN recommends establishing the following safeguards, if these costs are included in transition cost recovery: 1) if PG&E's pension expense in any year is less than the amount of the aggregate annual transition obligation, PG&E should be required to reduce its transition costs by the amount of the generation-related annual transition obligation which is paid by income generated internally by the pension fund and 2) PG&E's request for interest should be denied because PG&E has invested no money to create this regulatory asset. Similar to PBOPs, this regulatory asset is merely an accounting convention; therefore, no interest should be earned, moreover, PG&E does not earn interest on this amortization under current ratemaking procedures.

For SDG&E, TURN recommends disallowing the regulatory asset balance. TURN observes that for ratemaking purposes, pension payments are recognized to the extent that they are tax-deductible under Federal rules, while expenses are calculated on an actuarial basis. Contributions are deductible for tax purposes only if money actually needs to be contributed to the pension funds to ensure that adequate funds are available to pay benefits. Because the actuarial definitions of adequate funding are often more conservative than tax requirements, the difference between the pension cost for book purposes and ratemaking purposes (based on the maximum tax-deductible cash contribution to the fund) has increased. Pension funds have also had large increases in the value of their assets, as the stock market has risen in recent years. TURN explains that while these facts may create larger regulatory assets, they should not lead to corresponding increases in transition cost recovery.

17.4.1. Discussion

We are troubled by the utilities' requests for transition cost recovery for regulatory assets associated with pension expenses and the pension transition obligation. We have clearly never authorized a regulatory asset associated with the difference in accounting required by SFAS 87 and that adopted for ratemaking purposes. The pension transition obligation is not a recorded regulatory asset, but is amortized in rates, and acknowledged in footnotes to the financial statements, as is the PBOP transition obligation. (RT: 1071; 1891). The unrecognized pension transition obligation was established in the past to correct prior pension under-funding through equal annual payments, without interest. PG&E, Edison, and TURN essentially agree on the methodology, if a net regulatory liability exists; i.e., the regulatory asset consisting of the pension transition obligation should be offset by the regulatory liabilities stemming from the amount by which ratemaking pension expense has exceeded financial reporting pension expense. If this calculation, as of January 1, 1998, results in a net regulatory liability, this amount should be credited to the transition cost balancing account (i.e., to reduce transition cost recovery). This would have the effect of using the existing regulatory liability to fund the existing transition obligation. We prefer this approach, rather than debiting the transition obligation regulatory asset through the transition cost balancing account, for the following reasons.

TURN demonstrated that the pensions are over-funded and no tax-deductible contributions have been made recently, nor are they expected in the near term. In D.95-12-055, we adopted PG&E's proposal to set pension costs according to the benefits accruing to current employees, but acknowledged that this funding level could result in contributions that are too high if PG&E reduces its work force. We determined that we would review these assumptions when PG&E has a general review of its rates, or PG&E should file an advice letter no later than December 31, 1999 proposing ratepayer refunds, if required. Absent the amortization of the pension transition obligation, both PG&E and Edison acknowledge that it is likely that a regulatory liability will result from the difference between ratemaking and financial reporting, i.e., tax-deductible contributions are limited because of over-funding. It is reasonable to require PG&E and Edison to offset this accounting obligation with the over-funded amounts, rather than increasing transition costs unnecessarily.

SDG&E's claim to $5.3 million stems from the difference in ratemaking and financial reporting, but does not appear to be related to its transition obligation. SDG&E does not agree that its pension fund is over-funded. We will apply the same treatment at this time, but will allow SDG&E to come forward in the annual transition cost proceeding to establish that the pension fund is under-funded, the derivation of the under-funding, if any, the interaction with its PBR, and why these amounts are eligible for transition cost recovery.

17.5. Environmental Compliance

PG&E explains that its Hazardous Substance Mechanism (HSM) balancing account and the environmental compliance regulatory asset work together in that the HSM represents costs already incurred for hazardous waste clean-up activities for environmental cleanup of specific sites, net of insurance proceeds or other recoveries.

The environmental compliance regulatory asset is a forecast of costs to be incurred for the same activities included in the HSM. These costs are in addition to those recovered in rates for decommissioning. These activities do not include clean-up activities associated with generating plant.[23] The sites covered by the HSM are manufactured gas plants or off-site disposal facilities. Thus, the environmental compliance regulatory asset reflects costs that PG&E is likely to incur in the future; recovery of such costs typically occurs in the HSM. PG&E wants to ensure that it has a fair opportunity to recover future costs associated with already-incurred environmental liabilities.

Ratepayers bear 90% of these costs; shareholders, 10%. The corresponding regulatory asset is the Environmental Compliance Mechanism (ECM), which reflects 90% of the costs PG&E forecasts to be incurred to complete PG&E's responsibility to clean up the sites covered by the HSM. The HSM allocates 70% of these costs to gas ratepayers and 30% to electric ratepayers. In the current ratemaking regime, that 30% would have been collected through bundled electric rates. PG&E now proposes to recover the generation portion through transition cost recovery.

PG&E has allocated 28% of the ECM regulatory asset to transition cost recovery. PG&E asserts that this calculation results in transition cost recovery for less than 10% of its overall estimate of the cleanup costs reflected in the ECM. PG&E explains that the remainder of the ratepayer obligations represented by the ECM (i.e., costs related to transmission and distribution) will continue to be collected through the HSM based on actual costs.

Edison records projected environmental remediation costs as regulatory assets if it is probable both that the obligation to expend funds has attached and that these costs would be recovered in rates. Edison explains that this approach is required by SFAS 105, Accounting for Contingencies, which requires that an estimated loss from

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[23] PG&E explains in Exhibit 37 that "because environmental clean-up was part of the estimates of non-nuclear decommissioning in the GRC and because of the normal workings within rate base of cost of removal in the GRC process, recovery of environmental decommissioning through the HSM was not necessary." (Exhibit 37, p. 2-3.)

a contingency should be accrued if it is probable that a liability has occurred and the amount of the loss can be reasonably estimated. Edison records its projected environmental remediation costs as regulatory assets because, as they are paid out over time, it is assumed that they will be recovered in rates, as has occurred in the past. While Edison states that is was not planning to estimate any recovery of these costs through the transition cost balancing account, since D.97-06-060 requires amortization of its generation-related regulatory assets by 2001, Edison is now requesting that this amortization be based on the estimated 1998 balance, which it asserts is also PG&E's position. The auditors question the entire estimated amount of $9.6 million, stating that there is no specific authorization for recovery of these costs in AB 1890. Edison maintains that such costs are properly recorded and that recording costs as a regulatory asset does not require that the Commission pre-approve that classification. Edison maintains that whether a cost is recorded as a regulatory asset is based on criteria set forth in FASB 71. Edison disputes FEA's contention that this specific regulatory asset had not been identified as being collected in rates as of December 20, 1995, and contends that this is a category of costs clearly covered by § 367.

SDG&E has no environmental compliance costs for which it seeks transition cost recovery. SDG&E asserts, however, that if the unbundling proceeding results in the elimination of the hazardous waste balancing account for generation operations, SDG&E should then be able to seek transition cost recovery for these costs in the annual transition cost proceedings.

In general, ORA would not take issue with the transition cost recovery of the environmental compliance regulatory asset, so long as provisions for a true-up are included in the accounting mechanisms. However, ORA concurs with the auditors that PG&E's estimating and allocation methodologies are not clear, and thus these costs should not be eligible for transition cost recovery until the independent auditors are satisfied with the reasonableness of this methodology. ORA recommends that if these costs a · afforded transition cost recovery, PG&E's estimates should be made subject to refund ntil ORA has reviewed this account in PG&E's upcoming GRC.

TURN and FEA propose to exclude these costs from transition cost recovery. TURN recommends excluding PG&E's estimates of environmental compliance costs because they are not linked to any specific environmental projects at generating plants. Moreover, PG&E did not determine with any specificity which, if any, sites were generation-related. PG&E states that costs at specific generating plants are excluded from the HSM and the ECM; however, TURN explains that PG&E allocated costs to generation based on an allocation factor that includes all generation sites. TURN concludes that such costs are based on speculative estimates and also believes that there is great potential for double-counting with decommissioning costs or capital additions. TURN prefers Edison's methodology for estimating these costs, but insists that the timing of the spending is not definite, nor is it clear whether or not these costs may be reflected in plant divestiture. TURN recommends that if any of these costs are eligible for transition cost recovery, the funds collected should be treated as rate base offsets until the money is actually spent on generation-related projects.

FEA agrees with the auditors that PG&E was unable to substantiate its methodology for determining that the clean-up costs equal 28% of its plant assets and how these were allocated to the generation function. FEA is concerned about PG&E's proposal to collect generation environmental compliance costs from electric and gas transmission and distribution customers. FEA contends that these costs should be recovered in prices charged for electric generation; collection of these costs through transmission and distribution rates would confer a competitive advantage on the utilities. FEA recommends that because Edison has not been authorized to recover these costs as a regulatory asset and Edison has not substantiated the reasonableness of these estimated costs, this amount should be excluded from transition cost recovery.

We agree with the auditors that the nature of the costs recorded in the ECM account is speculative. PG&E's methodology underscores the uncertain nature of determining these costs. In D.97-06-060, we stated, "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 is established."

(D.97-06-060, mimeo. at p. 44.) We decline to grant transition cost recovery for this regulatory asset over the 48-month transition period because of the uncertain and indefinite nature of these costs. We see no reason to increase transition costs because of "phantom" costs that may or may not occur in the future. Indeed, the development of the cost estimates does not appear to fit the criteria established by SFAS 71. We find that recovery of these uncertain future costs is not allowed under § 367: these may be generation-related regulatory assets, but the costs were not being collected in rates as of December 20, 1995. We will not allow any costs to be charged to the transition cost balancing account at this time. If environmental compliance costs are actually incurred and spent on generation-related projects, the utilities may request recovery in the annual transition cost proceedings. It is not reasonable to allow these sorts of speculative costs to add to the already large transition cost bill. This approach is consistent with our findings in D.97-08-056, in which we determined that as of January 1, 1998, allowing entries into PG&E's and Edison's Hazardous Substance Clean-up and Litigation Cost Accounts (also called HSM accounts) for additional generation-related costs would confer a competitive advantage on these utilities.

17.6. Gain or Loss on Reacquired Debt and Preferred Stock

As Edison explains, this issue encompasses not only the costs of reacquiring debt and preferred stock, but also the debt and preferred stock premium or discount associated with each issuance. Edison's regulatory assets and obligations include costs and discounts associated with debt issuances plus costs associated with reacquiring and reissuing preferred stock. Under current ratemaking, these costs are recovered through the embedded cost of debt. Future costs may arise as a result of the utilities' reducing debt and preferred stock levels in their capital structures.

PG&E has reported future cost estimates for the amortization of the recorded loss on reacquired debt account, which is categorized as a regulatory asset, and does not ask for recovery of the unamortized debt discount. PG&E is seeking recovery for both past unamortized losses on debt costs and for any future losses that may be incurred. The amortized loss balance, net of any gains, was updated for

December 31, 1997, to reflect changes in the 1995 balance, taking into account normal amortization of the loss. The loss on reacquired debt is amortized over the remaining life of the original debt reacquired and retired. The auditors tested the December 31, 1995 balance and believe that this amortization is reasonable. The auditors, however, question as speculative and unreasonable the additional costs related to the forecasted losses in 1997. The auditors state that PG&E's assumptions associated with the 1997 recallable bonds may or may not materialize depending on the economic benefit at the time of recall in 1997. The auditors recommends that we establish criteria for allowing the utilities to retire debt and to recover any associated losses in the transition cost balancing account. If the 1997 callable debt does meet this established criteria, the auditors recommend that the calculation of any loss be determined at the time the debt is retired.

PG&E contends that the retirement of debt in 1997, including any loss on reacquired debt, is consistent with anticipated reacquisitions or refinancings of debt. PG&E maintains that true-ups will be made when actual information is available. PG&E states that the actual recorded value of the regulatory asset as of December 31, 1997 will be the basis for transition cost recovery.

Edison recommends that all recorded unamortized debt costs that are currently being recovered through the embedded cost of debt element in the rate of return continue to be recovered in this fashion. Edison explains that this is necessary because it is not possible to separate debt and preferred stock costs related to the part of the capital investment that is being reduced. Thus, the unamortized costs will decline as restructuring continues and issues mature without being replaced. As capital investment associated with generation is reduced, the remaining unamortized debt and preferred stock expenses will be supported by transmission and distribution plant. Edison and TURN agree that these costs are not stranded. Edison recommends that any future costs incurred to reacquire debt and preferred stock, which would be identifiable as transition-related, should be collected through the transition cost balancing account, rather than through the embedded cost of debt.

SDG&E proposes to recover both losses on reacquired debt and unamortized debt discount by way of transition cost recovery. The auditors do not question the amortization of either the December 31, 1995 balances for SDG&E or the additional amounts as of January 1, 1998.

FEA asserts that only actual incurred losses should be allowed for transition cost recovery. TURN, as noted above, agrees with Edison that costs associated with past transactions should not be eligible for transition cost recovery because they are not stranded. Unamortized costs will follow the existing debt issues to non-generation uses. TURN concurs with Edison's expectation that most of the bonds would not be called but would shift from generation to distribution.

TURN recommends that the allowance of future costs related to losses on reacquired debt as a result of calling debt because of the issuance of rate reduction bonds or other transition cost recovery must be read very narrowly. TURN urges that costs and benefits must be aligned and believes that it would not be equitable to collect CTC from ratepayers for the costs of calling in more expensive debt, only to allow the utilities to keep the savings resulting from the reduced embedded cost of debt. TURN maintains that a distribution utility has much less risk than a generating utility and could operate with a more leveraged capital structure, and that furthermore we must evaluate prudence issues with regard to debt issuances made in the 1995-97 time period when restructuring efforts were pending. TURN recommends that if either of the requested debt cost components are deemed eligible for recovery, we must adjust ratemaking to prevent double-counting, because the embedded cost of debt already contains a component to pay for losses on reacquired debt and unamortized debt discounts.

We agree with Edison and TURN that past unamortized debt costs included in the embedded cost of debt and should not be accounted for in the transition cost balancing account. Such an accounting would be complicated and has the potential to lead to double-counting. However, we are not similarly convinced regarding future losses. Section 840(f) reads:

> "'Transition costs' means the costs, and categories of costs, of an electrical corporation for generation-related assets and obligations, consisting of generation facilities, generation-related regulatory assets, nuclear settlements, and power purchase contracts, including, but not limited to, voluntary restructuring, renegotiations, or terminations thereof approved by the commission, that were being collected in commission-approved rates on December 20, 1995, and that may become uneconomic as a result of a competitive generation market in that those costs may not be recoverable in market prices in a competitive market, and appropriate costs incurred after December 20, 1995, for capital additions to facilities existing as of December 20, 1995, that the commission determines are reasonable and should be recovered, provided that these costs are necessary to maintain the facilities through December 31, 2001. Transition costs shall also include the costs of refinancing or retiring of debt or equity capital of the electrical corporation, and associated federal and state tax liabilities."

On August 15, 1997, SB 477 was signed into law by Governor Wilson. Among other things, SB 477 amends § 367 by adding the following sentence:

> "These uneconomic costs shall include transition costs as defined in subdivision (f) of Section 840, and shall be recovered from all customers or in the case of fixed transition amounts, from the customers specified in subdivision (a) of Section 841, on a nonbypassable basis...."

While SB 477 also amends § 840, it does not modify the language of § 840(f).

Pursuant to the law, we will allow the recovery of future costs associated with future losses incurred to reacquire debt and preferred stock as of January 1, 1998. While we are swayed by Edison's argument that the utilities have incentives to maintain an optimal capital structure, we will allow only those costs actually incurred, net of any gains, and carefully review such costs in the annual transition cost proceedings. We will require the utilities to make a showing at that time to demonstrate that adequate ratemaking safeguards are in place to ensure that the savings in the embedded cost of debt are adequately accounted for and that no double-counting has occurred.

17.7. Deferred Taxes

During informal workshops announced at evidentiary hearings and open to all parties, PG&E, Edison, SDG&E, ORA, and TURN were able to achieve consensus on property-related tax issues, PG&E's vacation pay deferred tax asset, and Edison's ad valorem lien date tax asset and presented a joint proposal addressing these issues (Exhibit 101). The parties sponsoring Exhibit 101 were available for cross-examination as a panel. These parties agree that transition cost taxes (also known as regulatory tax receivables) are fully eligible for recovery during the transition period. Parties have also agreed that all property-related regulatory tax receivables or payables will be amortized to zero by the end of the transition period, which will settle all property-related tax benefits or obligations between ratepayers and utilities, except as provided for in the decisions related to Diablo Canyon (D.97-05-088), Palo Verde (D.96-12-083), and SONGS (D.96-01-011 and D.96-04-059). Thus, the parties to this stipulation believe that the goals of the Preferred Policy Decision and AB 1890 are met and that this treatment fairly shares the benefits and costs during the transition period, concludes the obligations between ratepayers and utilities at the end of the transition period, and accommodates the requirements imposed by taxing authorities.

Although choosing not to participate in the tax workshops, EPUC now asserts that no tax regulatory assets are eligible for approval, because of the specific language of § 367(c).

We do not agree with EPUC. This joint proposal fairly addresses the property-related tax issues raised by parties to this proceeding, with regard to deferred tax liabilities, deferred tax assets, and deferred tax reserves. We adopt this stipulation, included in this decision as Attachment 5, and commend the parties for working through these complex issues. We particularly appreciate the clear, concise definitions and explanation of the ratemaking tax algorithm included in Appendix D to Exhibit 101.

17.8. Balancing Accounts

In compliance with the requirements of AB 1890 and D.96-12-077, PG&E, Edison, and SDG&E established Interim Transition Cost Balancing Accounts (ITCBA), effective January 1, 1997. PG&E recommends transforming any balance in the CAC account and the ERAM account as of December 31, 1997 to the ITCBA first, then to the Transition Cost Balancing Account (TCBA). PG&E proposes to eliminate ECAC and ERAM during the transition period and recover the cost categories addressed in these accounts through its proposed Transition Revenue Account (raised in the workshops addressing streamlining in the electric restructuring rulemaking, R.94-04-031/ I.94-04-032). For all costs incurred after December 31, 1997, PG&E agrees with CIU that costs which are not eligible for transition cost recovery and which are currently recovered in the ECAC or ERAM (for example, going forward costs for non-must-run fossil plants) should not be recovered in the transition cost balancing account. PG&E states that it does not propose to debit such ineligible costs to its transition cost balancing account. However, PG&E disputes FEA's proposal to remove such ineligible costs before December 31, 1997, because these costs were incurred under the current regulatory framework and, for ECAC costs, are subject to reasonableness review. If we find that these costs are not reasonable, PG&E states its intent to remove those costs at that time. The December 31, 1997 ERAM balance is not subject to reasonableness review, but is based on authorized GRC base revenue amounts with changes to reflect sales fluctuations.

Edison explains that the ITCBA was established to hold any overcollections in the ECAC and ERAM balancing accounts as of December 31, 1996, (see § 368 (a)) to receive the balances in the ECAC and ERAM balancing accounts on December 31, 1997, and to accrue any interim transition costs that the Commission may approve for recovery. Edison will transfer the balances in the ITCBA when the final transition cost balancing accounts are approved. Edison proposes to transfer the December 31, 1997 balances in the ITCBA, the SONGS 2&3 ICIP balancing account, and the Palo Verde Incremental Costs balancing account to the TCBA as subaccounts. Edison disputes CIU's and FEA's contention that we must take care to remove any costs not eligible for transition cost recovery from the ECAC and ERAM balancing accounts before those accounts are transferred to the TCBA. Edison explains that any balance remaining in the ECAC or ERAM balancing accounts as of December 31, 1997 will have arisen from differences between authorized and recorded costs and revenues since the date of the last true up of those accounts, and therefore, cannot be considered going forward costs. Aside from our policy that overcollections resulting from disallowances should be directly refunded to ratepayers rather than credited against transition costs, Edison asserts that there is no restriction to crediting overcollections or debiting undercollections in the ECAC and ERAM balancing accounts as of December 31, 1997 against transition costs.

SDG&E states its intent to record any overcollections in the ECAC and ERAM balancing accounts as of December 31, 1997 to the TCBA, which it believes is consistent with the mandates of AB 1890 and the requirements of D.96-12-077. ORA recommends that it is the recorded balancing account balances as of January 1, 1998 which should be the basis for transition cost recovery.

We concur that it is equitable to allow transition cost recovery for both undercollections and overcollections accrued in the ECAC balancing accounts as of December 31, 1997. This finding was addressed in D.96-12-077:

> For 1997, authorized ECAC revenues will continue to be a part of the authorized revenue requirement. The balancing function of ECAC will operate somewhat differently as a result of the rate freeze. If ECAC costs are higher than forecasted, then authorized revenues will be insufficient to cover these costs, and the resulting "undercollection" will eventually result in a higher authorized revenue requirement (assuming the costs are reasonable and subject to the rate freeze). Since rates may not rise to amortize the undercollection, however, the effect is to reduce the headroom revenues available for crediting to the interim TCBA. Similarly, if ECAC costs are lower than forecasted, a larger headroom and greater credit to the interim TCBA will result.

Balances in PG&E's, Edison's, and SDG&E's ECAC and ERAM accounts should be transferred to the ITCBAs or the TCBAs, if established, as of December 31, 1997, as part of the "closing" of those accounts. The ITCBA, in turn, should be closed out to the TCBA established for each utility. We emphasize that reasonableness reviews will continue for these amounts. To the extent headroom is insufficient to address any ECAC or ERAM undercollections, these amounts may not be carried over to later years for transition cost recovery, nor are such costs to be accumulated for later collection. The rate freeze is just that - a freeze, rather than a deferral.[24]

The auditors have confirmed the amounts included as credits in the ITCBA to account for the 1996 ECAC and ERAM overcollections for each utility:

PG&E: $ 51.6 million

Edison: $220.4 million

SDG&E: $ 98.1 million

We intend to carefully oversee and review the transfer of balances into the TCBA, including verifying the balances in the ECAC and ERAM balancing accounts. In addition, we will ensure that all headroom revenues, which may have been recovered in various utility accounts under the rate freeze, are properly credited to the TCBA. We direct the Energy Division to oversee an audit of the balances transferred to the TCBA and the headroom revenues. The Energy Division may select independent auditors to undertake this audit, if necessary. The audit report should be issued by December 31, 1998. If independent consultants are hired, we will require the utilities to pay for the audit, in proportion to the audit expense incurred. The utilities should file an advice letter on December 12, 1997 which details the costs and revenues to be transferred to the TCBA.

17.9. PG&E's WAPA Regulatory Asset

PG&E has a long-standing contract, terminating January 1, 2005, with the Department of the Interior, Bureau of Reclamation, Western Area Power

[24] As provided for in the proposed streamlining decision, ERAM accounts should be eliminated as of January 1, 1998. Edison no longer has an ERAM account. SDG&E's ERAM account no longer serves its original, intended purpose. PG&E's Transition Revenue Account will substitute for ERAM, to a certain extent.

Administration (WAPA) which is an exchange of power that includes requirements to coordinate the PG&E and WAPA electrical systems. When WAPA has excess power, the power is supplied to PG&E. PG&E then incurs an obligation to send power to WAPA at an unspecified future time. Power received from WAPA generally costs less than power supplied by PG&E. To account for these transactions, PG&E records a regulatory liability from WAPA with a corresponding regulatory asset which represents a receivable from ratepayers, which is then recoverable in a subsequent ECAC proceeding.

The auditors had not received enough information from the company to verify the WAPA regulatory asset balance. PG&E requested and was allowed to update its data by presenting additional information to the auditors. While the auditors continue to believe that the WAPA regulatory asset is eligible for transition cost recovery, they also recommend that this balance remain in the category of a questioned cost because PG&E has not presented detailed estimates in a manner which they can review adequately. The auditors explain that PG&E anticipated a FERC filing in July or August 1997 which would true-up the transactions through December 1995. This filing can be relied upon to substantiate the WAPA liability and regulatory asset balance as of December 31, 1995.[11]

The auditors recommend that PG&E prepare a reconciliation of the settlement amounts and provide documentation showing that accounts have been properly adjusted; this settlement amount should then become the basis for the eligible transition cost balance as of December 31, 1995. The auditors also recommend that PG&E show the necessary calculations to enable parties to discern how monthly dollar values are developed and added together to produce estimated account activity for the

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[11] On September 18, 1997, PG&E served on all parties to this proceeding the August 30 filing submitted to FERC which proposes true-up rates for the WAPA-PG&E exchange agreement. This filing proposes true-up rates for 1994 and 1995 energy and capacity rates and based on these proposed revisions, WAPA owes PG&E approximately $6.2 million.

two years ended December 31, 1997, but believe that additional testing of PG&E's work in regard to these data elements is not necessary.

PG&E agrees with this recommendation and proposes that the Commission review these calculations in the first annual transition cost proceeding. PG&E proposes to amortize the WAPA regulatory asset based upon actual recorded levels beginning January 1, 1998, with any differences from estimates subject to review in the annual transition cost proceedings. ORA supports the recovery of the WAPA regulatory asset. FEA recommends excluding this regulatory asset from transition cost recovery until PG&E provides the necessary support and required calculations.

We will adopt the auditors' recommendations and will require PG&E to support the calculations for the December 31, 1997 WAPA regulatory asset balance in the first annual transition cost proceeding by providing a detailed explanation of the monthly dollar amounts and how these amounts result in the regulatory asset balance. We will allow PG&E to amortize the WAPA regulatory asset or liability based on the substantiated December 31, 1995 balances.

17.10. PG&E's QF Buyout Regulatory Asset

PG&E has identified five QF contracts that were restructured or bought out prior to December 31, 1995. In accordance with generally accepted accounting principles, PG&E recorded the present value of this buyout liability and recorded a corresponding regulatory assets, anticipating Commission approval of recovery of these costs. Following the audit report, PG&E disclosed that it had discovered certain errors in the net present value calculations and revised them accordingly. The auditors performed additional analysis to verify these amounts. The auditors have confirmed that the adjusted balances for the QF Buyout regulatory asset are $173.2 million and $40.6 million as of December 31, 1995 and January 1, 1998, respectively. The auditors explain that these are still questioned costs because the Commission has not yet issued its decision in the ECAC proceeding in which PG&E seeks approval of the agreements and recovery of the related costs. PG&E states that it will adjust the balance of this regulatory asset to reflect any adjustment made by the Commission.

FEA accepts the restated amounts, but recommends that this regulatory asset would represent a cost eligible for transition cost recovery only when it is approved by the Commission.

Similar to our treatment of Edison's fuel and fuel transportation contracts which are not yet approved, we provide that the QF Buyout Regulatory Asset amounts for costs incurred prior to December 31, 1995 should be tracked in a memorandum account and transferred to the transition cost balancing account upon our determination of reasonableness.

18. Rate of Return Issues

In this proceeding, we must determine two important issues related to rate of return. First, we must decide when and to which assets the reduced return applies to non-nuclear transition cost assets; for example, plant assets are traditionally subject to the return on rate base, while other assets, such as fuel inventories, balancing account over- and undercollections, or regulatory assets, either earn the commercial paper interest rate or no rate of return.[25] Second, we must determine the appropriate embedded cost of debt rate to use in calculating the lower return.

In the Preferred Policy Decision, we found that a reduced return on equity was appropriate for those utility assets afforded transition cost recovery to reflect the reduced business risk associated with the recovery of the remaining net investment due to the imposition of a nonbypassable charge on distribution customers. (Preferred Policy Decision, mimeo, p. 124.) We have affirmed that the reduced return on equity set forth in the Preferred Policy Decision needs no adjustment at this time and that AB 1890 confirms this treatment:

> "Further, we agree that AB 1890 confirms the rate of return on equity we adopted in the Preferred Policy Decision. PU [Public Utilities] Code Section 367(d) states, in pertinent part: 'Recovery of costs prior to

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[25] The applicable reduced rates of return have been considered previously for nuclear generation assets in D.96-04-059, D.96-12-083, and D.97-05-088.

> December 31, 2001, shall include a return as provided for in Decision 95-12-063, as modified by Decision 96-01-009, together with associated taxes." (D.97-07-059, mimeo. at p. 2 quoting D.96-12-088, mimeo. at 33.)

On February 24, 1997, ORA filed a motion in R.94-04-031/I.94-04-032 requesting an immediate ruling ordering PG&E, Edison, and SDG&E to implement the provisions regarding the reduced return on equity. Timely responses to ORA's motion were filed by PG&E, Edison, SDG&E, and TURN.

We responded to this motion in D.97-07-059 by directing PG&E, Edison, and SDG&E to establish memorandum accounts to track the difference in revenue requirements between the authorized revenue requirement and the maximum reduction in revenue requirements. We also stated that we would not decide the merits of ORA's proposal without a full consideration of the interaction of the rate of return and transition cost recovery. Because this motion was filed and served in the electric restructuring rulemaking, but rate of return issues associated with transition cost recovery are being addressed in the transition cost proceedings, we allowed supplemental testimony or briefs to be submitted in Phase 2 of this proceeding. By ruling of July 25, 1997, the ALJ established that supplemental opening briefs would be filed on August 8 and supplemental reply briefs would be filed on August 18. We will summarize the positions of parties on these issues, either as articulated in the briefs.

ORA and TURN submit that the reduction in the return on equity should be implemented now because the utilities' risk of recovering their investments has already been reduced. ORA and TURN believe that several aspects of the statute have combined to substantially reduce the risk of recovery of eligible transition costs, including the establishment of the nonbypassable CTC, the implementation of the rate freeze, and the imminent issuance of the rate reduction bonds. ORA and TURN contend that beginning the rate freeze on January 1, 1997 creates headroom which in turn allows the utilities to begin collecting revenues to apply to transition costs prior to the beginning of the transition period. ORA argues that this increased headroom would increase the likelihood that utilities would be able to recover their transition costs within the specified time period and could result in early recovery of those costs, so that the rate freeze could end early.

ORA believes that this reduction in authorized revenue requirements would have been most appropriately applied beginning on January 1, 1997, when the rate freeze began, pursuant to D.96-12-077. In that decision, we also established interim balancing accounts to ensure that excess revenues collected under the rate freeze would be allocated to reducing transition costs. (D.96-12-077, mimeo. at pp. 12-13.) ORA recommends that a corresponding ratepayer benefit should be adopted. TURN supports ORA's proposal and emphasizes that the reduction in the return on equity portion of assets eligible for transition cost recovery will increase the likelihood of the utilities achieving full recovery of their stranded investment during the transition period. TURN also believes that this proposal will make recovery of transition costs more orderly, as required by § 330(t), because the reduced rate of return would be implemented at approximately the same time as the risk-reducing measures go into effect.

Furthermore, ORA and TURN argue that the reduced return should be applied to all utility generation rate base, not merely to those assets which are recovered on an accelerated basis. ORA and TURN explain that it is the opportunity to accelerate recovery of these asses, not the actual acceleration, which reduces the risk of recovery and thereby justifies the reduced rate of return. ORA and TURN are concerned that applying the reduced rate of return only to accelerated assets, rather than to all assets eligible for acceleration, would encourage gaming of this process. ORA and TURN contend that the utilities could have the incentive to forestall acceleration of as many assets as possible consistent with achieving full recovery during the rate freeze period, in order to maximize the return earned on those assets; therefore, the rate of return on various plant assets would vary not because of any difference in risk of recovery, but merely because of the acceleration decision. ORA and TURN recommend applying that reduced rate of return immediately to all assets eligible for transition cost recovery.

ORA and TURN also argue that D.97-07-059 is in error in prescribing use of 1995 cost of debt figures to compute the reduced return on equity for PG&E, Edison, and

SDG&E. ORA and TURN assert that D.96-04-059, which stated the fixed 1995 cost of debt should be broadly applicable, can apply only to SONGS assets only. ORA contends that these issues were not properly before the Commission in the SONGS settlement addressed in the Edison Test Year 1995 GRC (in which proceeding D.96-04-059 was issued), nor should the broad applicability have been addressed in D.97-07-059. ORA explains that the embedded cost of debt is traditionally determined in the annual cost of capital proceedings and the most recent determination of this component should be used to compute the reduced rate of return. ORA recommends that to the extent parties have negotiated a specific cost of debt as part of a settlement which has been approved by the Commission, it is that embedded cost of debt which should be the basis for the reduced return on those particular assets. For all other assets eligible for transition cost recovery, ORA recommends using the embedded cost of debt adopted in D.96-11-060 (the most recent cost of capital decision) to compute the reduced return on equity for each utility.

PG&E, Edison, and SDG&E recommend that we reject ORA's motion, because transition cost recovery will not begin until January 1, 1998; i.e., the non-nuclear generation assets will not receive accelerated depreciation treatment until that date. SDG&E states that D.96-11-060, the 1997 cost of capital decision, adopts an all-party settlement, to which ORA was a signatory. SDG&E believes that by seeking a reduction to the return on equity on assets which are eligible for transition cost recovery, ORA undermines its position in the cost of capital proceeding, and essentially seeks a rehearing of D.96-11-060, which is out of time.

PG&E also agrees that accelerated recovery of the uneconomic generation assets must be authorized before the reduced return component applies and that ORA's proposal is premature because the essential elements of the transition cost recovery framework are not yet fully implemented. PG&E states that a reduced return is appropriate only when an asset is determined to be uneconomic and the utility seeks to accelerate the recovery of that asset. Furthermore, PG&E states that the reduced return can apply only to fossil-fueled generation, pursuant to the Preferred Policy Decision, which PG&E believes clearly distinguishes between the treatment of fossil and hydroelectric assets. PG&E also claims that § 368(a) requires a distinction between returns applicable to economic and uneconomic assets, because it requires that "each utility shall amortize 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."

While PG&E acknowledges that the rate freeze has begun and makes revenues available to offset transition costs, it does not make any excess revenues available to those assets which are not accelerated. PG&E claims that neither the establishment of the ITCBA, the implementation of interim transition charges, nor the statutory authorization of the CTC reduces the utilities' risk of recovery of these assets; only the accelerated amortization of assets reduces the risk of recovery. Moreover, PG&E contends that it is not appropriate to reduce the rate of return applicable to economic assets, since these assets will not be accelerated or recovered in the transition cost balancing account. PG&E had used its 1996 cost of debt in calculating the reduced return on equity in its prepared testimony in this proceeding, but states that it would not be opposed to using the 1995 cost of debt.

Edison agrees that the reduced rate of return is tied to the accelerated recovery of generation assets and argues that neither the rate freeze, the nonbypassable CTC, nor implementation of the interim CTC justifies applying a reduced return to generation assets.[x] Edison concurs with PG&E that because in the Preferred Policy Decision, we established that the utilities would retain ownership of their hydroelectric assets, which would remain subject to traditional regulation, the reduced rate of return should not be applied to these assets. Edison recommends that the reduced rate of return should apply to Edison's fossil generation, once that generation has been market-valued and suggests that strict application of the principles articulated in the Preferred Policy

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[x] Edison filed a motion on August 11 to request that we accept its supplemental opening brief one day late, due to problems with its messenger service and the UPS strike. We grant that motion and Edison's supplemental opening brief is accepted for filing as of August 11, 1997.

Decision would mean that any generation assets not divested would not be subject to accelerated recovery until market valuation takes place. Edison explains that this approach is consistent with its position in Phase 1, in which it proposed to apply the reduced rate of return to assets that are being recovered on an accelerated basis, but a full rate of return would apply until that accelerated recovery begins.

SDG&E contends that ORA's motion to apply the reduced rate of return as of January 1, 1997 or February 7, 1997 (the date the motion was filed) should be dismissed, because retroactively implementing the reduced rate of return would constitute retroactive ratemaking. SDG&E also thinks the reduced rate of return is inextricably linked to the accelerated depreciation of the non-nuclear generation-related assets, and ORA's request directly contradicts D.96-11-060, the most recent cost of capital decision, and D.96-12-088, the Roadmap 2 decision. SDG&E disputes ORA and TURN's allegation regarding gaming, because SDG&E believes that the guidelines established in D.97-06-060 will preclude such gaming.

18.1. Discussion

In the Preferred Policy Decision, we found that it was appropriate to reduce the cost of capital for generation assets eligible for transition cost recovery by setting the return on the percentage of the undepreciated asset financed by equity at 10% below the long-term cost of debt. We also found that this reduced return was the appropriate measure of the reduced risk associated with these assets as the utilities recovered the net book value of such assets through accelerated depreciation. At the same time, we recognized that this 10% reduction could be eliminated by the utility divesting at least 50% of its fossil generation and stated that we would provide for a 10-basis point increase in return on equity for each 10% of fossil plants divested.

Furthermore, we found that ratepayers should benefit to some degree from our treatment of transition costs and that it would be inappropriate to require ratepayers during the transition to bear the same costs they would have borne in the absence of moving toward a competitive framework. We also found that it was equitable that shareholders recover somewhat lower revenues for transition cost assets than they would under traditional cost-of-service regulation and that assurance of full recovery would have the potential of providing perverse incentives to utility market behavior. The assurance of full recovery would allow the utility to remain indifferent to the level of transition costs and could even result in incentives to bid low in offering output to the Power Exchange, which could then depress the market-clearing price and further increase transition costs. Finally, we found that adopting a reduced return on equity was appropriate in light of the reduced risk of recovery and would not adversely impact the utilities' financial stability.

As stated in D.96-12-088, AB 1890 confirms the return on equity adopted in the Preferred Policy Decision. Although accelerated amortization of certain transition cost assets has not yet begun, the rate freeze commenced on January 1, 1997, pursuant to D.96-12-077. The utilities may be using this interim period to accrue revenues to offset transition costs.

We do not agree with the utilities that the application of the reduced rate of return is inextricably linked to the accelerated amortization of generation assets. In the Preferred Policy Decision, we established that we are not required to guarantee full transition cost recovery, and this has been affirmed in AB 1890. We also clarified that in allowing the utilities the opportunity to recover generation plant-based transition costs, we were also establishing an appropriate risk-based rate of return. We explained some of the genesis of our decision-making process and provided background information on Humboldt Bay Unit III and SONGS I, for which we provided shareholders less than full recovery of the combination of sunk costs and rate of return at the weighted cost of capital. (45 CPUC2d 274; 11 CPUC2d 532.) Neither of these decisions linked these outcomes with accelerated depreciation, although accelerated depreciation was allowed for SONGS I at the authorized rate of return. Furthermore, in D.85-08-046, we specifically established that while PG&E should recover the remaining net plant investment of Humboldt Bay 3 over a four-year period, no return was allowed on the unamortized balance:

> "With respect to PG&E's equity argument, we observe that plants which have exceeded their estimated useful lives have been fully

> depreciated. Thus, the shareholder has already recovered his entire investment and a fair return on that investment from the ratepayer. The ratepayer who has paid for the entire plant is entitled to receive any additional benefit from the plant's continued operation. In the case of premature retirement, the ratepayer typically still pays for all of the plant's direct cost even though the plant did not operate as long as was expected. The shareholder recovers his investment but should not receive any return on the undepreciated plant. This is a fair division of risks and benefits." (D.85-08-046, 18 CPUC2d 592, 599.)

In allowing the recovery of generation plant-related transition costs, we have, in effect, allowed the utilities to recover costs of plants that may no longer be used and useful in the new competitive marketplace. In the Preferred Policy Decision, we stated:

> "We expect that some utility plants will no longer be used and useful in the future restructured energy marketplace. Allowing recovery of remaining net investment associated with the SONGS I plant at the embedded cost of debt was reasonable at the time, given the then-current regulatory structure. However, today's decision decreases the risk associated with recovery of remaining net investment (now part of transition costs), due to the imposition of a nonbypassable charge on distribution customers...which decreases utility business risk." (Preferred Policy Decision, mimeo. at 124.)

We agree with ORA and TURN that this decreased business risk trigger the reduced rate of return. We tie the application of the reduced rate of return, not to accelerated depreciation, bur rather to the reduced risk because transition cost recovery was allowed in the first place. The necessary components of this decreased risk are in place, contrary to PG&E's and Edison's contentions. Indeed, these elements were firmly established when AB 1890 was signed into law and established that the utilities would have a reasonable opportunity to collect uneconomic costs and affirmed the nonbypassable competition transition charge. In addition, by starting the rate freeze on January 1, 1997, we have allowed the utilities the opportunity to accrue revenues that will serve to offset transition costs. The ratepayers might otherwise have enjoyed the benefits of lower rates. It is therefore equitable that the reduced rate of return apply to those generation plant assets that are currently in rate base and that are eligible for transition cost recovery. Furthermore, this reduced rate of return should have been applied as of January 1, 1997; we agree with SDG&E, however, that we cannot apply this reduced rate of return before the date on which the utilities established the memorandum accounts ordered in D.97-07-059.

Furthermore, we are persuaded that, for non-nuclear generation plant, the relevant cost of debt to be used in the calculation of the reduced return on equity is that adopted in D.96-11-060, in the 1997 cost of capital proceeding. While D.96-04-059 addressed the broad applicability of the concept of a fixed cost of debt, proper notice was not provided to all parties to the electric restructuring rulemaking that this decision, issued in Edison's 1995 Test Year GRC, had applicability beyond the SONGS 2&3 settlement. Fixing the reduced return on equity at 90% of the 1995 cost of debt for all utilities could impact parties' rights. We have carefully considered the reduced return on equity adopted in D.96-04-059 and D.97-07-059. Based upon the briefs and comments in this proceeding, the record developed in this proceeding now persuades us to reconsider fixing the reduced return on equity at 90% of the 1995 embedded cost of debt. It is more reasonable to establish the reduced return on equity at 90% of the 1997 embedded cost of debt adopted in D.96-11-060, which reflects the most recent information regarding risk and reward as reflected in the cost of capital. D.97-05-088 adopted a reduced rate of return for Diablo Canyon based on the 1996 cost of capital decision (D.97-05-088, mimeo., Finding of Fact 41 at p. 79; PG&E Opening Brief, p. 136.) We agree with the concept that the measure of the embedded cost of debt should remain fixed for the entire term of the transition period or the relevant amortization period, irrespective of changes in the actual utility embedded cost of debt. However, as a benchmark, PG&E, Edison, and SDG&E shall use the embedded cost of debt adopted in D.96-11-060 to calculate the reduced return on equity for transition cost recovery of generation-related plant assets. The reduced rate of return is 7.13% for PG&E, 7.22% for Edison, and 6.75% for SDG&E. For the nuclear generating plants, the reduced rate of return should be that established in D.96-04-059, D.96-12-083, and D.97-05-088 for SONGS 2&3, Palo Verde, and Diablo Canyon, respectively.

19. Issues for Transition Cost Annual Reviews

PG&E recommends that the filing date of June 1, 1998, as established for the first annual transition cost proceeding in D.97-06-060, is not consistent with recovery of 1999 transition costs on an ex post basis. Instead, PG&E recommends changing this date to require a filing by early 1999 (no later than May 1) for review of transition costs recorded in 1998. PG&E intends to provide a report of all entries to the transition cost balancing account, as well as the balances and returns used to develop transition cost revenue requirements, the assumptions used in estimating market value, the results of any actual market valuations, any changes in revenue requirements resulting from capital additions proceedings, changes in amortization schedules due to changes in market value estimates or actual market valuations, and any additional acceleration beyond the 48-month amortization schedule. PG&E also recommends a review of the entries to the must-run and non-must-run fossil memorandum accounts.

PG&E recommends that the annual proceeding should be an ex post review to determine that the transition cost balancing account entries are correct, based on recorded amounts, subject to any constraints adopted in this proceeding, the capital additions proceedings or generation PBR proceedings. PG&E strongly cautions against a prudence review of costs, other than QF buyout costs, although PG&E recognizes that certain costs must be reviewed for reasonableness by the Commission, including employee-related transition costs, WAPA true-ups, and must-run operating costs if not recovered though the ISO (because this is consistent with PG&E's placeholder proposal in this regard). PG&E agrees with ORA that there should continue to be reasonableness review of QF, purchased power, and geothermal steam contract administration costs, as well as of its water purchases. PG&E disagrees with ORA's recommendation to review Helms pumped storage costs, because PG&E believes that since power purchased for pumping purposes would be at the market-clearing price, reasonableness reviews are unnecessary.

PG&E recommends that these proceedings also audit the costs associated with operations and revenues received from the ISO and the Power Exchange. However, because scheduling of must-take resources, QF generation, and PG&E's own generation resources will be under FERC jurisdiction, PG&E recommends that no review of PG&E's bidding strategy occur in the annual transition cost proceedings. Thus, PG&E believes that the creation of the Power Exchange and the ISO transfers to FERC the oversight for ensuring that PG&E matches load and resources to provide least-cost, reliable service.

Edison proposes to file monthly and annual reports which address the recorded transition cost balancing account entries, similar to the monthly ECAC balancing account reports currently submitted to the Commission. Edison agrees with the timing of the first annual transition cost proceeding and recommends that this proceeding address forecast issues, estimated transition cost recovery in the following year, forecast capital additions, and estimated market value of assets subject to market valuation. Edison also recommends that this proceeding address reasonableness issues, including accelerated recovery of transition costs, review of recorded transition cost balancing account entries (including any recorded capital additions), contract administration, and the results of any plant valuations.

Edison recommends that since the annual transition cost application will be filed on June 1 of each year, the recorded information provided for review should cover the record period of April through March, similar to its current ECAC record period. For example, the June 1998 application would contain transition cost balancing account entries for January - March 1998. The June 1999 application would contain entries for April 1998 through March 1999.

ORA supports PG&E's suggestion to report recorded costs to date and focus in the first proceeding on reviewing future amortization schedules. ORA recommends that the utilities' management of power purchase contracts and QF contracts, PG&E's geothermal steam contracts, and PG&E's and Edison's water purchases and pumped storage operation costs all be addressed for reasonableness in the annual proceedings, which should also be used to address the determination of the uneconomic portion of Edison's coal contracts.

SDG&E succinctly recommends that the Commission address two groups of costs in the annual proceedings: an accounting of the previous year's expenditures and revenues and a review of any new costs which should be recovered as transition costs; e.g., employee-related transition costs. The amount of currently authorized generation-related operating expenses included in base rates should be confirmed as an upper limit as to how much can be recovered for going forward operating costs when an individual unit is required for reactive power/voltage support.

FEA recommends requiring the utilities to mitigate their transition costs and that these mitigation efforts should be the subject of annual Commission review.

19.1. Discussion

We have previously determined that all transition cost balancing account entries shall be subject to review in the annual transition cost proceedings. For now, we will retain the filing date of June 1, 1998 for the first annual transition cost proceeding. While there will only be three or four months of recorded data, we should have additional information regarding market valuation and recalibrated amortization schedules. This first proceeding may be somewhat attenuated, but by addressing these issues early, we will be able to implement any required changes to our approach in a timely fashion. Thereafter, the annual transition cost proceedings should review recorded data on a calendar-year basis.

PG&E, Edison, and SDG&E should provide monthly reports of all entries to the transition cost balancing account, as well as the balances and returns used to develop transition cost revenue requirements, the assumptions used in estimating market value, the results of any actual market valuations, any changes in revenue requirements resulting from capital additions proceedings, changes in amortization schedules due to changes in market value estimates or actual market valuations, and any additional acceleration beyond the 48-month amortization schedule. We will also require a review of the entries to the must-run and non-must-run fossil memorandum accounts.

We will require that all cost and revenues related to Power Exchange and ISO revenues be justified and subject to an audit. We will review various costs which have been determined to be eligible for transition cost recovery, consistent with our findings in D.97-06-060 and this decision. For example, we will address the reasonableness of employee-related transition costs, purchased power contract administration, QF contract administration, geothermal contract administration, water purchases, and PG&E's WAPA true-up. In addition, we will consider the utilities' mitigation efforts regarding off-site common and general plant and will review the assessments of Edison's land assets surrounding its gas-fired fossil plants. We will also review such recorded cos: · as the losses associated with reacquired debt and other actual costs the utilities present for transition cost recovery. ECAC costs recorded through December 31, 1997 will continue to be considered in traditional reasonableness reviews. Finally, we reiterate our instructions to the utilities to seek authority for recovery of transition costs not considered in this decision by filing new applications, rather than advice letters. The advice letter process is inappropriate for requesting this sort of recovery.

20. Conclusion

We have reviewed the utilities' requests for a transition cost recovery for various assets, costs, and cost categories. Because we have discussed several complex issues in this decision, we summarize our findings here and in Attachments 3 and 4.

The utilities should track actual costs and revenues on a plant-specific basis for both must-run and non-must-run plants. Any excess revenues should be credited to the transition cost balancing account annually. The revenues accrued in the memorandum account will earn the reduced transition cost rate of return. No interest rate or rate of return will be applied to any debit balances in that account. The only instances in which we will consider transition cost recovery for must-run plants are for those particular units operating at particular times that plant is actually called upon for reactive power/voltage support (and not any other "must-run" purpose) and for which the ISO contract has not provided recovery of operating costs, and the units are otherwise authorized to recover market-based rates. It is possible that under proposed Agreement A, the utilities will not recover all operating costs from ISO revenues; however, the desired solution is for the utilities to negotiate to move to Agreement B, rather than receiving assured transition cost treatment. The utilities must clearly demonstrate that the units are necessary for reactive power/voltage support and that transition cost recovery is only for that period during which contract terms are adjusted approximately at the ISO. Proposed Agreement C does not allow for market-based rates and is based on cost-of-service; therefore, no transition cost recovery is permitted for units under this proposed contract. The memorandum accounts will allow the necessary tracking to occur so that any modifications to our procedures can be executed efficiently and easily.

We accept the auditors' findings regarding the net book value of plant assets as of December 31, 1995. As of January 1, 1998, the net book value as of December 31, 1995 should be amortized over the 48-month transition period, consistent with the requirements established in D.97-06-060. The net book value should account appropriately for accumulated depreciation and deferred taxes. As the capital additions proceedings are completed, we will allow adjustments to net book value to reflect our findings in these proceedings and to account for depreciation for 1996 and 1997.

The gain or loss resulting from sale of assets, including land, should flow through the transition cost balancing account. Any loss associated with sale of assets should be amortized over the transition period, but any gain should be credited to offset transition costs and close out the appropriate subaccount.

As of January 1, 1998, materials and supplies inventories are going forward costs. Unamortized materials and supplies balances should not earn a rate of return. A physical inventory of materials and supplies inventories should be undertaken as of December 31, 1997, or as close to that date as possible, and the fair market value of the inventory components should be assessed. In the alternative, the utilities may deem the book value of the December 31, 1997 materials and supplies inventories balances to equal their market value. The utilities should file these market value assessments in the applications to market value their retained assets, which shall be filed on March 2, 1998.

We will defer consideration of the transition cost recovery of fuel oil inventory pending the ISO's determination as to whether these inventories are necessary for system reliability. For 1998 only, the utilities may apply the 3-month commercial paper rate to the unamortized balance of the level of fuel oil inventories. In addition, Edison shall file a proposal to account for the revenue-sharing mechanism for revenues accruing from third-party transportation on its fuel oil inventory pipelines, consistent with D.94-10-044. This proposal shall be filed on March 2, 1998 as part of Edison's application to approve retained assets. Edison's gas inventories and coal inventories should be market valued as of December 31, 1997, similar to our findings for materials and supplies inventories. Replenishment of inventory levels after January 1, 1998 will not be eligible for transition cost recovery. Carrying costs should not be allowed on any unamortized difference between market and book value. In the alternative, Edison may deem the book value of the December 31, 1997 gas and coal inventories balances to equal their market value.

Environmental and non-environmental non-nuclear decommissioning costs should continue to be recovered at the level currently included in authorized rates. The accumulated decommissioning amortization should be accounted for as an offset to rate base, at least until such time as the generating plants are market valued, and should not be accelerated. The timing of environmental decommissioning should be accounted for in a net present value calculation, to the extent that environmental decommissioning is expected to occur after 2001. Hydroelectric negative net salvage should not be recovered as a separate item in the transition cost balancing account, but should be factored into PG&E's depreciation reserve.

CWIP costs incurred prior to December 31, 1995, which are not approved for recovery in separate capital additions proceedings for 1996 and 1997, and are not included in divestiture are not eligible for transition cost recovery. RWIP costs should continue to be treated as an increase to the accumulated depreciation reserve. After market valuation, ratepayers will no longer be responsible for additional costs associated with retiring a plant, including decommissioning. CWIP costs associated with past hydroelectric relicensing costs will be considered in the market valuation of hydroelectric assets.

The on-site common and general plant estimates should be amortized over the transition period, using the December 31, 1995 amounts which have been verified by the auditors. Off-site common and general plant assets are excluded from transition cost recovery at this time.

The sale of excess emissions credits results in a gain on sale of utility property which should be credited to the TCBA to offset transition costs.

Edison should prorate land according to its functions and should remove all land associated with generating assets to be divested from rate base upon the date of divestiture. Only the book value of land classified as generation and which Edison has proposed to divest with the underlying generating assets and land allocated to fuel oil pipelines shall be amortized through the transition cost balancing account at the reduced rate of return. We will defer ruling on land associated with fuel-oil pipelines until the ISO has made its determination regarding these assets, but Edison should address this land in its proposal to ensure that ratepayers continue to benefit from the revenue-sharing mechanism adopted in D.94-10-044. When Edison has completed its analysis confirming the pro-rata assignment of land to functions and the appraisal of land is completed, the transition cost balancing account shall be trued-up as appropriate. This analysis should be included in the March 2, 1998 filing. Land should be valued as of the date of divestiture, if not before, and the transition cost balancing account should be credited appropriately.

In conformance with FERC's classification of step-up transformers and generation radial-tie lines as generation assets, these assets should be eligible for transition cost recovery.

The fixed ICIP prices adopted for Diablo Canyon and SONGS 2&3 will be compared to the Power Exchange market-clearing price to determine ongoing transition cost recovery. Because of the balancing account treatment adopted in D.96-12-083, we will compare Palo Verde's incremental operating costs as billed by Arizona Public Service with the market-clearing price, rather than the fixed ICIP cost approach which we have implemented for Diablo Canyon ad SONGS 2&3. We will rely on the ICIP prices adopted in D.96-04-059 to compute any necessary transition cost recovery or offsets.

PG&E's and SDG&E's requests for fixed costs related to fuel and fuel transportation contracts are denied. Other than the exceptions provided Edison, fuel and fuel transportation costs are going forward costs not eligible for recovery in the transition cost balancing account. Edison's fuel costs should be recovered from market revenues, to the extent possible. The uneconomic portion of Edison's fixed costs of its fuel and fuel transportation contracts must be calculated by comparing fixed costs to the market-clearing price for natural gas fuel and transportation.

Transition cost recovery of QF contract costs and interutility contract costs will be based on actual per-kilowatt-hour costs incurred compared to the Power Exchange market-clearing price. Each utility should establish subaccounts in its transition cost balancing account to track QF contract costs, interutility contract costs, BRPU settlement costs, and QF contract restructurings and buyouts.

The revenue requirements established for hydroelectric and geothermal assets should be based on the net book value adopted in these proceedings. Market revenues earned for hydroelectric and geothermal assets should be tracked in a memorandum account and compared to the revenue requirements established for these assets, and excess revenues should be credited to offset transition cost recovery. The reduced rate of return should apply to hydroelectric and geothermal assets, which should be recovered in the transition cost balancing account. Market revenues in excess of revenue requirements should be credited to the transition cost balancing account on an annual basis. Similar to the memorandum accounts established for the fossil must-run and non-must-run plants, any excess revenues accruing in a particular month will earn the reduced transition cost rate of return, rather than the commercial paper rate. No interest rate or rate of return will be applied to any debit balances in that memorandum account.

Costs associated with employee benefits must be included in current operating costs and recovered from market revenues for all such generation-related expenses accrued <u>after</u> January 1, 1998. Because PG&E accounts for workers' compensation on a "pay-as-you-go" basis, rates include costs that would have also been included in the actuarial calculation for post-1998 obligations of the workers' compensation regulatory asset. PG&E's request for transition cost recovery of workers' compensation costs is denied.

Because we have approved accrual accounting treatment for the long-term disability obligation and we can establish a cut-off point for going forward costs, this obligation is eligible for transition cost recovery. Transition cost recovery is authorized for Edison's post-employment benefits associated with claims prior to 1998. No rate of return should apply to the unamortized balance. PG&E's post-employment benefits should be accounted for similarly to Edison's and the initial obligation as established in D.95-12-055 should be amortized over the transition period. No rate of return should be applied to the unamortized balance.

The PBOP regulatory assets and transition obligations are eligible for transition cost recovery and should be amortized ratably over the transition period, based on the December 31, 1997 estimates which represent actuarial determinations with no rate of return applied to the unamortized balance. For PG&E, it is reasonable to apply the discount rate of 9% that was adopted in D.95-12-055. These accelerated amounts are to be placed in the appropriate trust funds for each utility; to the extent they are not so deposited, these amounts will be treated as a rate base offset with a corresponding credit to the transition cost balancing account. We will allow a tax gross-up only to the extent these contributions to the trust are tax deductible. PBOP amounts should not be contributed to the trusts until they are tax-deductible. Any money which is collected but not yet contributed then becomes a rate base offset, which is reduced by deferred taxes associated with the asset for the taxes due when the money is collected. Edison's estimates of costs related to Mohave coal mine employees for PBOP expenses are denied transition cost recovery at this time.

For pensions, the regulatory asset, consisting of the pension transition obligation, should be offset by the pension regulatory liabilities. The net regulatory liability should then be credited to offset transition cost recovery. For PG&E, pensions are overfunded and no tax-deductible contributions have been made recently. It is reasonable to require PG&E to repay the pension transition obligation with the overfunded amounts, rather than increasing transition cost recovery unnecessarily. We will exclude SDG&E's claim for its pension regulatory asset from transition cost recovery, but it is reasonable to allow SDG&E to demonstrate that its pension is under-funded in the annual transition cost proceeding.

The environmental compliance regulatory asset is a forecast of costs to be incurred on the same activities included in the HSM. These activities do not include those associated with generating plant. The costs recorded in the environmental compliance regulatory asset are speculative and should be excluded from transition cost recovery unless actually incurred during the transition period. If the utilities incur environmental compliance costs for generation-related projects, PG&E, Edison, and SDG&E may seek recovery in the annual transition cost proceedings.

We will allow transition cost recovery for actual losses incurred to reacquire debt and preferred stock, net of gains, and will review these costs in the annual transition cost proceedings. We will require the utilities to make a showing in the annual transition cost proceedings to demonstrate that adequate ratemaking safeguards have been implemented to ensure that the savings in the embedded cost of debt are adequately accounted for and that no double-counting has occurred.

Transition cost taxes (regulatory tax receivables) are fully eligible for recovery during the transition period. All property-related regulatory tax assets and payables will be amortized to zero by the end of the transition period, which will settle all property-related tax benefits or obligations, except as provided for the nuclear generating facilities in D.97-05-088, D.96-12-083, and D.96-01-011 and D.96-04-059.

1997 ECAC and ERAM balances should be transferred to the transition cost balancing account, in conformance with D.96-12-077.

PG&E may amortize its WAPA regulatory asset or liability based on trued-up December 31, 1995 amounts. PG&E must support its December 31, 1997 calculations in the annual transition cost proceeding. PG&E's QF buyout regulatory asset should not receive transition cost recovery until these amounts are determined to be reasonable.

The reduced rate of return should apply to non-nuclear generation assets currently in rate base and eligible for transition cost recovery, except as described in this decision, beginning on the date on which the utilities established the memorandum accounts provided for in D.97-07-059. The reduced rate of return for non-nuclear generating assets shall be calculated based on the embedded cost of debt adopted in D.96-11-060. PG&E's reduced rate of return for transition cost purposes is 7.13%; Edison's reduced rate of return is 7.22%; and SDG&E's reduced rate of return is 6.75%. The embedded cost of debt shall remain fixed for the entire term of the transition period or relevant amortization period, irrespective of whether the utility's cost of debt changes.

Using a market-based approach to transition cost recovery is consistent with the law and preferable from our policy standpoint. The next step, and the most important step for purposes of determining the economic or uneconomic portion of these categories, is market valuation. Ensuring that market valuation occurs soon in the transition period is essential to the final determination of transition cost recovery for those assets subject to market valuation, will ensure that transition cost recovery is expeditious and orderly, and will eliminate the burdensome tracking requirements that must exist until this occurs. To expedite this process, we order PG&E, Edison, and SDG&E to file applications no later than March 2, 1998 to establish the principles necessary to appraise their retained assets. PG&E, Edison, and SDG&E should file separate applications no later than March 31, 1998, to provide for review of the restructuring implementation costs, addressed in § 376. Although we have previously considered the possibility that these issues would be consolidated in Phase 3 of these proceedings, we will now require separate applications. This approach will facilitate our decision-making process and lead to more efficient resolution of these issues.

To implement the findings in this decision, PG&E, Edison, and SDG&E are directed to finalize their transition cost balancing account tariffs. PG&E, Edison, and SDG&E shall file compliance advice letters by December 12, 1997, which shall be effective as of January 1, 1998, unless the Energy Division determines that these tariffs are not in compliance with this decision. These final tariffs shall incorporate the findings addressed in this decision, including the elimination of various categories for transition cost recovery, the implementation of placeholders for others, and, depending on the category, identifying the applicable rate of return, commercial paper rate, or no interest rate as appropriate.

Transition cost balancing account pro forma tariffs have been the subject of various workshops convened by the Energy Division. The most recent round of workshops was held on August 26, 27, and 28, 1997. The Energy Division issued its workshop report on September 16. Comments on the workshop report were filed on September 25. Several issues were raised in the workshop report which are not addressed herein, and will be addressed in a separate decision issued before the end of the year. Parties will be afforded the opportunity to comment on that decision.

21. Comments on Proposed Decision

PG&E, Edison, SDG&E, ORA, TURN, DOD, EPUC, and Enron filed timely comments on the proposed decision.[97] PG&E, Edison, SDG&E, CIU (jointly with CLECA, CMA, and Farm Bureau), ORA, TURN, and Enron filed reply comments.

We have incorporated these comments throughout the decision as appropriate. 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.

Findings of Fact

1. The need for forecasts of transition cost amounts is eliminated by the rate freeze and the residual calculation of the CTC.

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[97] Gordon Allot, Esquire also filed comments. Mr. Allot is not a party to this proceeding, nor did he request to participate in these proceedings, in accordance with either Rule 53 or Rule 54 of our Rules of Practice and Procedure. We will therefore not consider Mr. Allot's comments. Furthermore, we note that one of Mr. Allot's arguments appears to be a broad challenge to the statute itself and are thus not relevant to the particulars of the instant proceeding. Administrative agencies, including this Commission, cannot determine the constitutional validity of any statue. (Constitution of the State of California, Article III, § 3.5.)

2. The assessment of whether assets and costs are economic or uneconomic must be made on an asset-specific basis.

3. If a generation facility is likely to be economic on an overall basis, specific costs associated with that plant will not be eligible for treatment as transition costs.

4. A careful tracking of eligible transition costs and accrued revenues is necessary to ensure that we can confidently track recovery on an asset-specific basis.

5. Net book value is defined as original cost less accumulated depreciation and amortization in determining eligibility of various costs and cost categories for transition cost recovery, including an appropriate accounting of the impact of deferred taxes on the net book value quantification.

6. Sunk costs are defined as undepreciated capital costs and costs which have already been incurred and cannot be avoided or reduced.

7. Going forward costs are defined as all costs necessary for the continued operation of the plant or unit, both variable and fixed.

8. It is premature to adopt an implementation methodology for the 150 basis point mechanism at this time, since no utility is claiming this incentive for its must-run plants.

9. All going forward costs must be recovered from market revenues before such incentive mechanisms as the 150 basis point mechanism may be applied.

10. Market mechanisms are preferable to administrative calculations of transition costs.

11. The utilities should establish memorandum accounts to track on a monthly basis actual going forward costs and market revenues on a plant-specific basis for both must-run and non-must-run plants. Any excess revenues should be credited to the transition cost balancing account on an annual basis. The revenues accrued in the memorandum account will earn the reduced transition cost rate of return. No interest rate or rate of return will be applied to any debit balances in that account.

12. The only instances in which we will consider transition cost recovery for must-run plants are for those particular units operating at particular times when the ISO calls on the plant for reactive power/voltage support (and not any other "must-run"

purpose) and for which the ISO contract has not provided recovery of operating costs, and the units are otherwise authorized to recover market-based rates.

13. It is possible that under proposed Agreement A, the utilities will not recover all operating costs from ISO revenues for the first 90 days of the transition period.

14. Proposed Agreement C does not allow for market-based rates and is based on cost-of-service; therefore, no transition cost recovery is permitted for units under this proposed contract.

15. The memorandum accounts we order will allow the necessary tracking to occur so that any modifications to our procedures can be executed efficiently and easily.

16. We have prescribed various guidelines in D.97-06-060 regarding order of recovery and acceleration, and have also stated that each asset should be depreciated to its market value, but not below, and that recalibration of the amortization may then be necessary. These guidelines will adequately capture the economic value of depreciation.

17. Market valuation allows us to obtain important information regarding economic and uneconomic costs for generating assets and assists us in determining if the rate freeze may end prior to March 31, 2002.

18. We accept the auditors' findings regarding the net book value of plant assets as of December 31, 1995.

19. As of January 1, 1998, the net book value of the fossil generating plants as of December 31, 1995 should be amortized over the 48-month transition period. The net book value should account appropriately for accumulated depreciation and deferred taxes. As the capital additions proceedings are completed, we will allow adjustments to net book value to reflect our findings in these proceedings and account for depreciation accrued in 1996 and 1997. The utilities may adjust the transition cost balancing account when assets are sold or market-valued to reflect the actual costs on the books. If decisions regarding capital additions are issued after the sale of a plant, the transition cost balancing account will be adjusted to reflect the outcome of those proceedings.

20. The gain or loss resulting from sale of assets, including land, should flow through the transition cost balancing account.

21. Any loss associated with sale of assets should be amortized over the transition period, but any gain should be credited to offset transition cost recovery and close out the appropriate subaccount.

22. The audit was conducted according to the directives of the August 1, 1996, assigned Commissioner Ruling and the audit procedures outlined in the auditors' workplan.

23. As of January 1, 1998, materials and supplies inventories are going forward costs.

24. Unamortized materials and supplies balances should not earn a rate of return.

25. A physical inventory of materials and supplies inventories should be undertaken as of December 31, 1997 or as close to that date as possible, and the fair market value of the inventory components should be assessed. In the alternative, the utilities may deem the book value of the December 31, 1997 materials and supplies inventories balances to equal their market value.

26. Allowing the difference between market value and cost of materials and supplies inventories as of December 31, 1997 to be eligible for transition cost treatment allows for a cohesive treatment of divestiture and transition cost recovery.

27. If the utilities deem the book value of the December 31, 1997 materials and supplies balances to equal their market value, the utilities should track the difference between the physical inventories existing as of December 31, 1997 and the physical inventories existing as of the date of actual market valuation. Changes in inventory levels are going forward costs and are not eligible for transition cost recovery.

28. It is appropriate to defer consideration of the transition cost recovery of fuel oil inventory pending the ISO's determination as to whether these inventories are necessary for system reliability.

29. For 1998 only, the utilities may apply the 3-month commercial paper rate to the unamortized balance of the level of fuel oil inventories.

30. For gas and coal inventories, it is reasonable to establish a bright line for determining uneconomic costs up to January 1, 1998 and going forward costs after that date. Thus, Edison should undertake a physical inventory of its gas and coal inventories

as of December 31, 1997, or as close to that date as possible, and the fair market value of the inventories should be assessed. Alternatively, Edison may deem the book value equal to the market value for gas and coal inventories.

31. It will be relatively simple to compare the market price of gas with the net book value of Edison's gas inventory.

32. The value of coal is not based on transporting it to a different site, but rather on its intrinsic market value.

33. If Edison deems the book value of the December 31, 1997 gas and coal inventory balances to equal their market value, Edison should track the difference between the physical inventories existing as of December 31, 1997 and the physical inventories existing as of the date of actual market valuation. Changes in inventory levels are going forward costs and are not eligible for transition cost recovery.

34. Replenishment of inventory levels after January 1, 1998 will not be eligible for transition cost recovery. Carrying costs should not be allowed on any unamortized difference between market and book value.

35. The HSM recovers costs that are not already recovered in rates, whereas environmental decommissioning is recovered in current rates through the decommissioning expense.

36. Because it is not probable that the environmental decommissioning responsibility can be transferred to new owners, we will allow the unrecovered portion of these costs, as currently authorized in rates, to be amortized as a current cost in the transition cost balancing account.

37. Environmental decommissioning costs will be accounted for as a rate base offset, as these costs are accumulated prior to being spent.

38. We will require appropriate true-ups and credits to the transition cost balancing account to reflect updated studies of environmental decommissioning costs, actual costs incurred, any transfer of this obligation to new owners, and any change in the method of recovery of these costs deemed appropriate by this Commission at the time of market valuation.

39. The market valuation process for both divested and retained plants will yield more accurate and useful values of non-nuclear non-environmental decommissioning costs than will an estimate of what these expenditures are likely to be.

40. Non-environmental non-nuclear decommissioning costs should continue to be recovered at the annual level currently included in authorized rates and amortized beginning January 1, 1998.

41. The accumulated decommissioning amortization should be accounted for as an offset to rate base, at least until such time as the generating plants are market valued.

42. There is no need for accelerated depreciation of the non-nuclear decommissioning expense, because the non-environmental amounts will be reflected in the market valuation process.

43. At the time of market valuation, amounts collected for both environmental and non-environmental decommissioning may be credited against liabilities for either decommissioning category.

44. It is not reasonable to treat fossil decommissioning costs as if all such costs will be incurred by 2001.

45. For plants retired before or during the transition period, true-ups should be made to the transition cost balancing account for actual decommissioning work (both environmental and non-environmental) and revised decommissioning studies. These costs will be reviewed in the annual transition cost proceeding.

46. The timing of decommissioning should be accounted for in a net present value calculation, to the extent that environmental decommissioning is expected to occur after 2001.

47. Hydroelectric negative net salvage should not be recovered as a separate item in the transition cost balancing account, but should be factored into PG&E's depreciation reserve.

48. The CWIP account includes costs for projects which were under construction prior to December 31, 1995.

49. CWIP costs incurred prior to December 31, 1995, which are not approved for recovery in separate capital additions proceedings are not eligible for transition cost

recovery. However, any CWIP remaining on the date a generation station is sold to a new owner should be reflected in both the book and market values of that station.

50. RWIP costs should continue to be treated as an increase to the accumulated depreciation reserve.

51. After market valuation is finalized for each plant, ratepayers will no longer be responsible for any additional costs associated with retiring a plant, including decommissioning costs not addressed in the market valuation process.

52. Common plant is defined as those assets associated with more than one utility service, such as gas and electricity.

53. General plant includes several categories of costs not assignable to more specific accounts.

54. On-site common and general plant is generation-related assets that are integral to the operation of the generating plant.

55. It is reasonable to allow amortization of the on-site common and general plant recorded amounts at the December 31, 1995 levels which have been verified by the auditors.

56. The market valuation process should capture the value of on-site common and general plant assets.

57. The majority of items in the category of off-site common and general plant assets will likely be usable in other functions and should be excluded from transition cost recovery.

58. Emission trading credits are used by the utilities to offset certain air pollution emissions under a program established by federal statute.

59. Excess emission trading credits are those not needed by the utilities and can be bought and sold in a secondary market.

60. The sale of excess emissions credits results in a gain on utility property which should be refunded to ratepayers either through credits to the transition cost balancing account or as an offset to net eligible transition costs.

61. PG&E and Edison should include proposals in the divestiture proceedings for computing and applying the increase in the reduced rate of return applicable to the

non-nuclear and non-hydroelectric equity components, of up to 10 basis points for each 10% of fossil generating capacity divested.

62. PG&E and Edison should establish tracking accounts to track the differential in the non-nuclear and non-hydroelectric equity component of the reduced rate of return as each 10% of fossil generating capacity is divested, which would then be applied to the reduced rate base.

63. Edison should prorate land according to its functions and should remove all land associated with divested generating assets from rate base upon the date of divestiture.

64. Only the book value of land which has been classified as generation and which Edison has proposed to divest with the underlying generating assets should be amortized through the transition cost balancing account at the reduced rate of return.

65. Land associated with transmission-related plant should not impact transition cost recovery and should continue to earn the authorized rate of return.

66. Land which is not included with divestiture and which is not allocated to fuel oil pipelines should be excluded from transition cost recovery at this time.

67. When Edison has completed its analysis confirming the pro-rata assignment of land to functions and the appraisal of land is completed, the transition cost balancing account should be trued-up as appropriate. Edison should present its pro-rata analysis to this Commission in the March 2, 1998 appraisal application.

68. It is reasonable to calculate the fair market value of all land associated with generation assets upon the date of divestiture, if not before, other than land associated with transmission plant and fuel-oil pipelines. The transition cost balancing account should be credited appropriately.

69. FERC has classified step-up transformers and generation radial-tie lines as generation assets and these assets should be eligible for transition cost recovery.

70. Edison's retrofits to SONGS' low pressure turbines increased plant safety and reliability and were not undertaken to increase capacity per se.

71. An increase in produced kilowatt hours has the potential to increase claimed transition costs if the Power Exchange price is less than the forecasted ICIP price.

Similarly, if the Power Exchange price is greater than forecasted ICIP prices, the increase in production has the potential to offset transition costs.

72. We will rely on the ICIP prices adopted in D.96-04-059 to compute any necessary transition cost recovery or offsets. Each kilowatt hour will continue to receive the ICIP price and will be compared with the Power Exchange market clearing price. Edison should incorporate this methodology in its final transition cost balancing account tariffs.

73. We will not allow Edison to track fuel contract and transportation costs that we have not yet determined to be reasonable through the transition cost balancing account.

74. Other than for the exceptions provided Edison, fuel and fuel transportation costs are going forward costs that are not eligible for recovery in the transition cost balancing account.

75. Edison's fuel costs, including coal reclamation and closure costs, should be recovered from market revenues, to the extent possible.

76. The uneconomic portion of Edison's costs of its fuel and fuel transportation contracts must be calculated by comparing costs to market revenues.

77. Edison's fuel and fuel transportation contract costs should be tracked in a memorandum account, until they are determined to be reasonable by this Commission.

78. Transition cost recovery of QF contract costs and interutility contract costs will be based on actual incurred costs compared to the Power Exchange market clearing price. As used in this context, the Power Exchange market-clearing price is equal to the day-ahead energy price and/or the price of ancillary services which can be economically provided through the contract.

79. The annual transition cost proceedings should include a review of QF contract administration and litigation costs.

80. Each utility should establish placeholder subaccounts in its transition cost balancing account to track QF contract costs, interutility contract costs, BRPU settlement costs, and QF contract restructurings and buyouts.

81. The generation PBR proceeding (A.96-07-009 *et al.*) has been modified to establish revenue requirements for PG&E's hydroelectric and geothermal assets and Edison's hydroelectric assets.

82. Certain issues associated with must-run hydroelectric plants and reasonableness of pumped storage costs will be considered in A.96-07-009 *et al.*

83. The revenue requirements established for hydroelectric and geothermal assets should be based on the net book value adopted in these proceedings.

84. Market revenues earned for hydroelectric and geothermal assets should be tracked in a memorandum account and compared to the revenue requirements established for these assets. Market revenues in excess of revenue requirements should be credited to the transition cost balancing account on an annual basis. Similar to the memorandum accounts established for the fossil must-run and non-must-run plants, any excess revenues accruing in a particular month will earn the reduced transition cost rate of return. No interest rate or rate of return will be applied to any debit balances in that memorandum account.

85. The reduced rate of return should apply to hydroelectric and geothermal assets, which will be recovered in the transition cost balancing account.

86. Costs associated with pumped storage assets should be recovered in the transition cost balancing account.

87. Employee benefits are tracked either by accrual accounting or the "pay as you go" method.

88. Accrual accounting occurs when the utility recognizes the costs of benefits as they are earned or attributed to an employee, as services are provided. For financial reporting purposes, utilities account for PBOPS, pension, workers compensation, and long-term disability benefits on an accrual basis.

89. Under "pay as you go" accounting, a utility recognizes an employee benefit cost when it actually pays such a benefit to the employee.

90. Costs associated with employee benefits must be included in current operating costs and recovered from market revenues for all such generation-related expenses accrued after January 1, 1998.

91. Because PG&E accounts for workers' compensation on a "pay-as-you-go" basis, rates include costs that would have also been included in the actuarial calculation for post-1998 obligations of the workers' compensation regulatory asset.

92. It is not reasonable to allow PG&E's workers' compensation regulatory asset to receive transition cost treatment at this time because of the potential for double recovery and the commingling of pre-1998 and post-1998 costs.

93. Because we have approved accrual accounting treatment for this obligation and we can establish a cut-off point for going forward costs, the long-term disability obligation is eligible for transition cost recovery.

94. It is reasonable to adopt the joint proposal by Edison and TURN regarding Edison's post-employment benefits.

95. Transition cost recovery is authorized for Edison's post-employment benefits associated with claims prior to 1998. No rate of return should apply to the unamortized balance.

96. PG&E's long-term disability obligation should be accounted for similarly to Edison's, and the initial obligation as established in D.95-12-055 should be amortized over the transition period. No rate of return should be applied to the unamortized balance.

97. The PBOP regulatory asset represents estimated costs for medical and life insurance benefits attributed to employee service which has accrued since 1993.

98. The PBOP transition obligation represents costs for benefits attributed to employee service which occurred prior to 1993.

99. The PBOP regulatory assets and transition obligations are eligible for transition cost recovery and should be amortized ratably over the transition period.

100. The PBOP regulatory assets and transition obligations should be amortized based on the December 31, 1997, estimates which represent actuarial determinations with no rate of return applied to the unamortized balance.

101. If post-retirement benefit plans are modified to reduce benefits during the transition period, which then reduces the actuarial basis of the transition obligations,

these true-ups should be accounted for as credits to the transition cost balancing account during the transition period.

102. For PG&E, it is reasonable to apply the discount rate of 9% which was adopted in D.95-12-055.

103. PBOP amounts should not be contributed to the trusts until they are tax-deductible. Any money which is collected but not yet contributed then becomes a rate base offset, which is reduced by deferred taxes associated with the asset for the taxes due when the money is collected.

104. Edison's estimates of costs related to Mohave coal mine employees for PBOP expenses are precluded from transition cost recovery at this time.

105. Under cost-of-service ratemaking, pension payments are recognized to the extent they are tax-deductible under Federal rules, while, under financial reporting, expenses are calculated on an actuarial basis.

106. Pension contributions are deductible only for tax purposes if amounts must be contributed to pension funds to ensure that adequate funds are available to pay benefits.

107. The pension transition obligation is amortized in rates, but is not a recorded regulatory asset.

108. The unrecognized pension transition obligation is an obligation established in the past to correct prior pension underfunding, in equal amounts, without interest.

109. The regulatory asset, consisting of the pension transition obligation, should be offset by the pension regulatory liabilities. The net regulatory liability should then be credited to offset transition cost recovery.

110. For PG&E, pensions are over-funded and no tax-deductible contributions have been made recently.

111. It is reasonable to require PG&E to repay the pension transition obligation with the over-funded amounts, rather than increasing transition cost recovery unnecessarily.

112. We will exclude SDG&E's claim for its pension regulatory asset from transition cost recovery, but it is reasonable to allow SDG&E to demonstrate that its pension is under-funded in the annual transition cost proceeding.

113. The environmental compliance regulatory asset is a forecast of costs to be incurred on the same activities included in the HSM. These activities do not include those associated with generating plant.

114. The costs recorded in the environmental compliance regulatory asset are speculative and should be excluded from transition cost recovery unless actually incurred during the transition period.

115. If the utilities incur environmental compliance costs for generation-related projects during the transition period, PG&E, Edison, and SDG&E may seek recovery in the annual transition cost proceedings.

116. Future costs related to reacquired debt and preferred stock may arise as a result of the utilities' reducing debt and preferred stock levels in their respective capital structures.

117. The embedded cost of debt includes a component to pay for unamortized debt discounts and these costs should not be eligible for transition cost recovery.

118. We will allow transition cost recovery for actual losses incurred to reacquire debt and preferred stock, net of gains, and will review these costs in the annual transition cost proceedings.

119. We will require the utilities to make a showing in the annual transition cost proceedings to demonstrate that adequate ratemaking safeguards have been implemented to ensure that the savings in the embedded cost of debt are adequately accounted for and that no double-counting has occurred.

120. Transition cost taxes (regulatory tax receivables) are fully eligible for recovery during the transition period.

121. All property-related regulatory tax assets and payables will be amortized to zero by the end of the transition period, which will settle all property-related tax benefits or obligations, except as provided for the nuclear generating facilities in D.97-05-088, D.96-12-083, and D.96-01-011 and D.96-04-059.

122. ECAC and ERAM balances as of December 31, 1997 may be transferred to ITCBA or to the transition cost balancing account. The ITCBA should then be transferred to the TCBA.

123. An audit is necessary to verify the transfer of balances in the TCBA, to review the balances in the ECAC and ERAM balancing accounts, and to ensure that all headroom revenues are properly credited to the TCBA.

124. It is reasonable to allow PG&E to amortize its WAPA regulatory asset or liability based on trued-up December 31, 1995 amounts. PG&E must support its December 31, 1997 calculations in the annual transition cost proceeding.

125. PG&E's QF buyout regulatory asset should not receive transition cost recovery until these amounts are determined to be reasonable.

126. SDG&E's abandoned projects regulatory asset and AMAX coal contract buyout regulatory asset are eligible for transition cost recovery.

127. The necessary components of transition cost recovery are in place and the utilities' risk of recovery is decreased commensurately.

128. By beginning the rate freeze on January 1, 1997, we have allowed the utilities to accrue revenues that may serve to offset transition costs.

129. If the rate freeze had not begun on January 1, 1997, the ratepayers may have enjoyed the benefits of decreased rates.

130. The calculation of the reduced rate of return for non-nuclear generating assets should be based on the cost of debt adopted for each utility in the 1997 cost of capital decision, D.96-11-060.

131. For the nuclear generating plants, the reduced rate of return should be consistent with that adopted in D.96-01-011 and D.96-04-059 for SONGS 2&3, D.96-12-083 for Palo Verde, and D.97-05-088 for Diablo Canyon.

132. We will retain the filing date of June 1, 1998 for the first annual transition cost proceeding.

Conclusions of Law

1. The notice requirement of § 370 does not require a specific forecast of transition costs, but rather the notification that such charges will be assessed.

2. PU Code § 367 gives utilities the opportunity to recover transition costs that are identified and determined by this Commission.

3. Our goal is to provide the utilities with a fair opportunity for full recovery of transition costs and to ensure that recovery of going forward costs is appropriately limited, consistent with the law.

4. The netting calculation required by § 367(b) does not preclude asset-by-asset transition cost tracking. The expeditious, orderly recovery of transition costs, as required by § 330 (t), requires this approach.

5. Section 367 includes generation-related regulatory assets and obligations as cost categories eligible for transition cost recovery. These costs cannot be excluded from such recovery, based on the definition of net book value for fossil assets.

6. Section 367(c)(1) refers specifically to particular plants or units providing reactive power/voltage support at particular times; we use this meaning in referring to must-run plants.

7. In D.97-04-042 and D.97-07-037, we determined that the 150 basis point incentive mechanism referred to in the Preferred Policy Decision applies only to must-run plants.

8. It is unlawful under § 367(c) to allow recovery of going forward costs through the transition cost balancing account.

9. The Legislature has stated that competition in electric generation is preferred to regulation, because it encourages innovation, efficiency, and better service from all market participants.

10. Market revenues from all sources which are in excess of costs should offset transition costs, as required by the Preferred Policy Decision and AB 1890.

11. It is not reasonable for the utilities to seek additional recovery through the transition cost balancing account for operating costs related to must-run units, to the extent the ISO limits payments to plants or units providing reactive power/voltage support.

12. Units and plants that operate under proposed Agreement C will not be eligible for transition cost treatment under § 367(c)(1).

13. The utilities must clearly justify transition cost recovery for operating costs for plants being operated for reactive power/voltage control purposes under Agreement A for the first 90 days of the transition period.

14. All non-nuclear generating assets are subject to market valuation by the end of 2001, as required by § 367(b). Nothing in AB 1890 prevents us from requiring market valuation to occur before the end of 2001.

15. It is reasonable to allow recovery of sunk costs associated with must-run units, because it is unlikely that any ISO call contract will recover all previously expended capital costs.

16. This Commission must make the final determinations regarding the eligibility of assets and cost categories for transition cost recovery.

17. It is not appropriate to allow the utilities to carry forward existing materials and supplies inventory into the new market, which could confer a competitive advantage on the utilities.

18. It is reasonable to appraise the market value of the materials and supplies inventories prior to divestiture and prior to our enactment of rules and procedures related to appraisal of retained generating assets, such as fossil-fired plants.

19. Deferring market valuation of inventories until the associated plant is either market valued or sold would allow changes in fuel inventory levels after January 1, 1998 to receive transition cost treatment.

20. Because the transition cost balancing account itself will be subject to the commercial paper rate of interest, there is no need to apply an additional interest rate calculation on those elements which would earn such a rate.

21. D.97-08-056 prohibits the utilities from entering any costs associated with generation into their HSM accounts.

22. In accordance with state and federal law, the utilities remain liable for contamination on power plant property.

23. CWIP costs incurred prior to December 31, 1995 which are not approved in separate capital additions proceedings do not meet the guidelines established for abandoned plant recovery.

24. Traditional ratemaking has provided that plant which is retired before the end of its useful life may continue to be depreciated, but does not earn a rate of return.

25. In D.95-12-051 and D.95-04-076, we generally found that the total net value of excess emissions credits should be returned to ratepayers.

26. Excess emissions credits do not fit the criteria established in D.96-12-025 regarding refunds made directly to ratepayers.

27. Accounting for excess emission credits through offsets to transition cost recovery conforms to the netting process established by § 367(b) and is consistent with our preference for market-based mechanisms.

28. Divestiture and other forms of market valuation are required by §§ 330(*l*)(2) and 367(b), to mitigate market power concerns and to transition utilities from regulated to unregulated status.

29. Sections 330 and 367 require a netting of all "above-market" and "below-market" transition cost assets to determine the costs to be recovered. Section 330 also requires that the transition to a competitive market be orderly, allow a fair opportunity to fully recover the costs associated with commission-approved generation-related assets and obligations, and be completed as expeditiously as possible. These two mandates demonstrate our duty to ensure that the market valuation process is structured to obtain maximum value of the property.

30. Pursuant to the Preferred Policy Decision and AB 1890, the ongoing ICIP costs, are compared to the market clearing price, and the difference between revenues and costs are either credited or debited, as appropriate, to the transition cost balancing account.

31. Because of the balancing account treatment adopted in D.96-12-083, we will compare Palo Verde's incremental operating costs as billed by Arizona Public Service with the Power Exchange market-clearing price.

32. It is not reasonable to interfere, in this decision, with the balance of risk and rewards that was adopted for the ratemaking treatment of SONGS 2&3.

33. Pursuant to § 367(c)(2), Edison may recover 100% of the uneconomic fixed costs of fuel and fuel transportation contracts, if these contracts were executed prior to December 20, 1995 and if the costs are determined to be reasonable by this Commission.

34. PG&E's and SDG&E's requests for transition cost recovery for fuel and fuel transportation costs should be denied, because they are not consistent with the exceptions delineated in § 367(c)(1) and 367(c)(2).

35. Section 367 affirms the Preferred Policy Decision's finding that the utilities are authorized to collect the ongoing transition costs resulting from the differences between QF contract prices and the Power Exchange market-clearing price and between interutility contract prices and the Power Exchange market-clearing price.

36. It is reasonable to track excess revenues resulting from comparing the hydroelectric and geothermal costs with Power Exchange prices and assets to use these revenues to offset transition cost recovery.

37. Hydroelectric and geothermal assets are subject to market valuation, pursuant to § 367(b).

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

39. We established regulatory asset treatment for PBOPs in D.91-07-006 and D.92-12-015.

40. In D.88-03-072, we declined to adopt SFAS 87 for ratemaking purposes. This decision applied to telephone carriers, but has been broadly applied to energy utilities.

41. It is not reasonable to increase transition costs because of phantom costs which may or may not occur in the future; the recovery of uncertain future costs is not allowed under § 367.

42. Pursuant to § 367, as amended by Senate Bill 477, and § 840(f), transition cost recovery should be allowed for future losses incurred to reacquire debt and preferred stock as of January 1, 1998.

43. The joint exhibit by PG&E, Edison, SDG&E, ORA, and TURN fairly resolves property-related tax issues, PG&E's vacation pay deferred tax asset, and Edison's ad valorem lien date tax asset.

44. It is equitable to allow transition cost treatment for both undercollections and overcollections accrued in the ECAC and ERAM balancing accounts as of December 31, 1997.

45. To the extent headroom is insufficient to address ECAC or ERAM undercollections, these amounts may not be carried over to later years for transition cost recovery, nor may such amounts be accumulated for later deferred collection.

46. In the Preferred Policy Decision, we established that it was reasonable to reduce the return on generation assets eligible for transition cost recovery by setting the return on equity at 90% of the embedded cost of debt.

47. The reduced rate of return is the appropriate measure of the reduced risk associated with these assets.

48. The Preferred Policy Decision provided for a 10-basis point increase in return on equity for each 10% of fossil plant divested.

49. With the recovery of generation plant-related transition costs, the utilities recover costs of plants that may no longer be used and useful in the new competitive marketplace.

50. It is the decreased business risk which triggers the application of the reduced rate of return, rather than accelerated depreciation.

51. The elements of transition cost recovery and the concomitant reduced risk were established when AB 1890 was signed into law and established that the utilities would have a reasonable opportunity collect uneconomic costs through the nonbypassable CTC.

52. It is reasonable to apply the reduced rate of return to generation assets currently in rate base and eligible for transition cost recovery, except as described in this decision, as of the date on which the utilities established the memorandum accounts provided for in D.97-07-059.

53. While D.96-04-059 addressed the broad applicability of the fixed 1995 cost of debt for purposes of the reduced return on equity, proper notice of this action was not provided and the parties' rights were impacted.

54. We adopted the 1996 embedded cost of debt for purposes of the reduced return calculation for Diablo Canyon in D.97-05-088.

55. The embedded cost of debt should remain fixed for the entire term of the transition period or relevant amortization period, irrespective of changes to each utility's cost of debt.

56. All transition cost balancing account entries are subject to review in the annual transition cost proceedings.

57. It is reasonable to review various costs that are eligible for transition cost recovery.

58. It is reasonable to consider the utilities' mitigation efforts regarding off-site common and general plant in the annual transition cost proceedings.

59. It is reasonable to review the assessments of Edison's land assets surrounding its gas-fired fossil plants.

60. This order should be effective today so that final transition cost balancing account tariffs may be implemented before January 1, 1998.

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 implement clear, straightforward language, which notifies the direct access customer of the obligation to pay transition costs in their respective tariffs.

2. PG&E, Edison, and SDG&E shall each establish a Power Exchange Revenue memorandum account and an Independent System Operator (ISO) Revenue memorandum account to track costs and revenues from all market sources for the non-must-run and must-run plants, respectively, as described in this decision. These memorandum accounts shall be reviewed in the annual transition cost proceedings and excess revenues shall be credited to offset transition costs on an annual basis. The revenues accrued in the memorandum account will earn the reduced transition cost rate of return. No interest rate or rate of return will be applied to any debit balances in those accounts.

3. PG&E, Edison, and SDG&E shall market value their respective materials and supplies inventories as of December 31, 1997 or as close to that date as possible. Transition cost recovery for materials and supplies inventory shall be allowed once that market valuation is completed according to the guidelines established in this decision, or by deeming the December 31, 1997 book value equal to market value for these inventories. PG&E, Edison, and SDG&E shall include these assessments in their March 2, 1998 applications for appraisal of retained assets.

4. Edison shall market value its gas and coal inventories as of December 31, 1997, or as close to that date as possible. For its gas inventories, Edison shall include this assessment in its appraisal application, as described in Ordering Paragraph 3. For its coal inventories, workshops will be held in the near future in the docket relating to Edison's application initiating market valuation by appraisal. Alternatively, Edison may deem the December 31, 1997 book value of its gas inventory balances and coal inventory balances equal to market value. In its appraisal application, Edison shall include a proposal for the treatment of fuel oil inventory which ensures that ratepayers continue to benefit from the revenue-sharing mechanism adopted in D.94-10-044.

5. With the exception of hydroelectric relicensing costs, to the extent that Construction Work in Progress (CWIP) costs incurred prior to December 31, 1995 are not approved in separate capital additions proceedings, or are not included in the plant balances being divested, PG&E's, Edison's, and SDG&E's requests for recovery of these costs are denied. Hydroelectric relicensing costs incurred prior to December 31, 1995 will be addressed in market valuation.

6. PG&E and Edison shall establish tracking accounts to track the differential in the non-nuclear and non-hydroelectric equity components of the reduced rate of return, as each 10% of fossil generating capacity is divested.

7. PG&E's and SDG&E's requests for transition cost recovery for fuel and fuel transportation costs are denied.

8. PG&E's request for transition cost recovery of the workers' compensation regulatory asset is denied at this time.

9. SDG&E's request for transition cost recovery for the pension regulatory asset is denied at this time.

10. Transition cost recovery of the environmental compliance regulatory asset is denied at this time.

11. The reduced rate of return shall be applied to generation assets currently in rate base and eligible for transition cost recovery, except as described in this decision, as of the date on which the utilities established the memorandum accounts provided for in Decision (D).97-07-059.

12. The reduced rate of return for non-nuclear generating assets shall be based on the embedded cost of debt adopted in D.96-11-060. For transition cost purposes, PG&E's reduced rate of return is 7.13%; Edison's reduced rate of return is 7.22%; and SDG&E's reduced rate of return is 6.75%.

13. The embedded cost of debt shall remain fixed for the entire transition period or relevant amortization period, irrespective of whether each utility's cost of debt changes.

14. PG&E, Edison, and SDG&E shall establish Transition Cost Balancing Accounts in compliance with the guidelines established in this decision, according to the following procedures:

a. PG&E, Edison, and SDG&E shall file compliance advice letters by December 12, 1997, which shall be effective as of January 1, 1998, unless the Energy Division determines that these tariffs are not in compliance with this decision.

b. The tariffs shall incorporate the findings addressed in this decision, including the elimination of various categories for transition cost recovery, the implementation of placeholders for others, and, depending on the category, identifying the applicable rate of return, commercial paper rate, or no interest rate, as appropriate.

c. PG&E, Edison,, and SDG&E shall file separate advice letters that detail the costs and revenues to be transferred to the transition cost balancing account as of January 1, 1998.

14. For the duration of the transition period, PG&E, Edison, and SDG&E shall provide monthly reports of all entries to the transition cost balancing account, as well as

the balances and returns used to develop transition cost revenue requirements, the assumptions used in estimating market value, the results of any actual market valuations, any changes in revenue requirements resulting from capital additions proceedings, changes in amortization schedules due to changes in market value estimates or actual market valuations, and any additional acceleration beyond the 48-month amortization schedule. These reports shall be submitted to the Energy Division and served on the parties to this proceeding. PG&E, Edison and SDG&E shall provide the Energy Division with three hard copies of each monthly report and an electronic version (on computer disk or via electronic mail) which contains each report and the underlying data, in either Word, Excel, or other format as specified by the Energy Division.

15. 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. All cost and revenues related to Power Exchange, ISO and other pertinent revenues must be justified and shall be subject to an audit.

16. As directed in D.97-06-060, 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.

17. In order to fully comply with Public Utilities Code § 367(b), PG&E, Edison, and SDG&E shall file applications no later than March 2, 1998 to establish the principles necessary to appraise their retained assets and to report assessments of the materials and supplies inventories, and, for Edison, the fuel inventories. As described in this decision, Edison shall include a proposal to ensure that ratepayers continue to benefit from the revenue-sharing mechanism for fuel oil inventory, adopted in D.94-10-044. Edison shall also include, in this application, its pro-rata analysis of its land, according to its function, i.e., transmission-related, fuel oil pipeline-related, and generating plant-

related, as well as Edison's proposal for treatment of fuel-oil pipeline land that is consistent with D.94-10-044.

18. In order to address restructuring implementation costs, pursuant to Public Utilities Code § 376, PG&E, Edison, and SDG&E shall file separate applications no later than March 31, 1998 to identify these costs.

19. The Energy Division shall oversee an audit of the balances transferred to the transition cost balancing account and the headroom revenues. The Energy Division may select independent auditors to undertake this audit, as described in this decision. The audit report shall be filed by December 31, 1998 and served on the service list to the first annual transition cost proceeding.

This order is effective today.

Dated November 19, 1997, at San Francisco, California.

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

I will file a concurring opinion.

/s/ JESSIE J. KNIGHT, JR.
Commissioner

ATTACHMENT 1
REQUEST FOR PLANT RELATED TRANSITION COSTS
INCURRED AS OF DECEMBER 31, 1995(1)
(Dollars In Thousands)

DESCRIPTION	PG&E	EDISON	SDG&E	TOTAL
Plant in Service				
Generation	4,799,488	2,832,717	429,532	8,061,737
Generation Related Transmission	265,202	48,728	5,772	319,702
General and Common Plant	83,076	42,929	4,388	130,393
Land and Land Rights	42,494	18,777	5,844	67,115
Intangibles	47,373	6,344	168	53,885
Other			16	16
Helms Regulatory Asset	14,593			14,593
Total Plant Investment	5,252,226	2,949,495	445,720	8,647,441
Reserves for Depreciation				
Accumulated Provision	(2,367,903)	(1,876,714)	(315,812)	(4,560,429)
Decommissioning Accrual	(114,056)			(114,056)
Retirement Work in Progress (2)		9,307		9,307
Total Reserves for Depreciation	(2,481,959)	(1,867,407)	(315,812)	(4,665,178)
Net Plant in Service	2,770,267	1,082,088	129,908	3,982,263
Other Plant Items				
Construction Work in Progress	35,265	64,959	20,461	120,685
Capitalized Leases			64,525	64,525
Total Other Plant Items	35,265	64,959	84,986	185,210
Plant Related Items and Taxes				
Materials and Supplies	14,214	39,387	10,635	64,236
Fuel Inventories	40,734	113,030	14,783	168,547
Accumulated Deferred ACRS/MACRS	(281,819)	(106,557)	(4,432)	(392,808)
Deferred Investment Tax Credit		(29,110)	(2,829)	(31,939)
SFAS 109 Deferred Tax Assets		5,185	45,311	50,496
Defense Deferred Taxes	(4,879)			(4,879)
Accumulated Deferred Tax - Fuel Oil		16,670		16,670
Environmental Compliance	9,066	15,128		24,194
Total Plant Related Items and Taxes	(222,684)	53,733	63,468	(105,483)
Regulatory Assets and Liabilities				
Flow Through Taxes		7,754		7,754
ECAC and ERAM Balances		(310,026)		(310,026)
Ad Valorem Lien Date Adjustments		3,265		3,265
Balancing Accounts	307,355			307,355
Geysers 15	9,793			9,793
WAPA Power Exchange	137,169			137,169
QF Buyouts	165,710			165,710
Humboldt Bay D&D	3,044			3,044
(Gain) Loss on Reacquired Debt	78,670		4,615	83,285
Debt Discount and Expense			1,727	1,727
SFAS 109 Deferred Taxes	996,690			996,690
Workers' Compensation	26,737			26,737
Long Term Disability	19,235			
PBOP	2,359		87	2,446
Unrecognized PBOP	54,620		2,714	57,334
Unrecognized Pension	11,929		(102)	11,827
Pension			5,439	5,439
Regulatory Liabilities	(23,214)			(23,214)
Abandoned Projects			2,965	2,965
PGE-AMAX Coal contract			4,384	4,384
Total Regulatory Assets and Liabilities	1,790,097	(299,007)	21,829	1,512,919
Total Costs for Eligibility	$ 4,372,945	$ 901,773	$ 300,191	$ 5,574,909

1. Excludes Contractual Obligations and Placeholders
2. Previously included in Construction Work in Progress (CWIP)

Source: Transition Cost Audit Report

ATTACHMENT 2
TRANSITION COST REQUESTS FOR ELIGIBILITY
(Dollars In Thousands)

DESCRIPTION	PG&E Revised Estimate of Eligible Transition Costs at January 1, 1998	Edison Revised Estimate of Eligible Transition Costs at January 1, 1998	SDG&E Revised Estimate of Eligible Transition Costs at January 1, 1998	Total Revised Estimate of Eligible Transition Costs at January 1, 1998
Plant in Service				
Generation	4,912,599	2,832,717	429,532	8,174,848
Generation Related Transmission	265,202	48,728	5,772	319,702
General and Common Plant	80,050	42,929	4,388	127,367
Land and Land Rights	42,494	18,777	5,844	67,115
Intangibles	47,373	6,344	168	53,885
Other			16	16
Helms Regulatory Asset	13,845			13,845
Total Plant Investment	5,361,563	2,949,495	445,720	8,756,778
Reserves for Depreciation				
Accumulated Provision	(2,541,738)	(1,876,714)	(352,515)	(4,770,967)
Decommissioning Accrual	(179,374)			(179,374)
Retirement Work in Progress		9,307	27,836	37,143
Total Reserves for Depreciation	(2,721,112)	(1,867,407)	(324,679)	(4,913,198)
Net Plant in Service	2,640,451	1,082,088	121,041	3,843,580
Other Plant Items				
Construction Work in Progress	8,071	63,059	4,993	76,123
Decommissioning Costs	775,542	365,266	70,479	1,211,287
Negative Net Salvage	338,271			338,271
Capitalized Leases			52,292	52,292
Total Other Plant Items	1,121,884	428,325	127,764	1,677,973
Plant Related Items and Taxes				
Materials and Supplies	13,947	39,387	10,635	63,969
Fuel Inventories	28,493	113,030	13,321	154,844
Accumulated Deferred ACRS/MACRS	(273,108)	(105,508)	(4,198)	(382,814)
Deferred Investment Tax Credit		(29,110)	(2,551)	(31,661)
SFAS 109 Deferred Tax Assets		3,785	32,451	36,236
Defense Deferred Taxes	(3,512)			(3,512)
Accumulated Deferred Tax - Fuel Oil		16,670		16,670
Deferred Capitalized Interest	13,383			13,383
TRA 1996 Vacation Day Deferrals	3,315			3,315
Environmental Compliance	11,725	9,644		21,369
Total Plant Related Items and Taxes	(205,757)	47,898	49,658	(108,201)
Regulatory Assets and Liabilities				
Flow Through Taxes		(6,213)		(6,213)
ECAC and ERAM Balances		(220,426)		(220,426)
Ad Valorem Lien Date Adjustments		3,265		3,265
Balancing Accounts	39,123			39,123
WAPA Power Exchange	101,633			101,633
QF Buyouts	43,619	126,000		168,619
Humboldt Bay D&D	1,515			1,515
(Gain) Loss on Reacquired Debt	76,481		4,071	80,552
Debt Discount and Expense			1,555	1,555
SFAS 109 Deferred Taxes	892,267			892,267
Workers' Compensation and LTD	46,634			46,634
PBOP	6,971		(3)	6,968
Unrecognized PBOP	47,645	52,403	2,394	102,442
Unrecognized Pension	9,019		(72)	8,947
Pension	(26,175)		5,682	(20,493)
Abandoned Projects			989	989
PGE-AMAX Coal contract			2,924	2,924
Total Regulatory Assets and Liabilities	1,235,732	(44,971)	17,540	1,208,301
Contractual Obligations				
QF Contracts	28,433,000	29,162,300	2,402,200	59,997,500
Unavoidable Fuel Contracts/ Buyouts		840,500		840,500
Wholesale Power Contracts		2,214,021	726,880	2,940,901
Irrigation District Contracts	939,300			939,300
Geysers Steam Contract	215,200			215,200
Interstate Transition Cost Surcharge	40,500		38,694	79,194
Total Contractual Obligations	29,628,000	32,216,821	3,167,774	65,012,595
Place Holders and Other Costs				
On-Going Cost of Constrained On Plan	621,000			621,000
NOx and HydroRetrofits and Relicense	258,313			258,313
Hydro - PBR		525,717		525,717
Restructuring Costs	61,877			61,877
1998 Projected Plant Additions	51,851			51,851
Total Place Holders and Other Costs	993,041	525,717		1,518,758
Total Transition Costs Eligibility	$ 35,413,351	$ 34,255,878	$ 3,483,777	73,153,006

Source: Exhibits 114 116

ATTACHMENT 3
Pacific Gas and Electric Company
Net Book Value
(Dollars in Thousands)

DESCRIPTION		Requested Sunk Costs December 31, 1995	Adopted Sunk Costs at December 31, 1995		Rate of Return in Percent
Plant in Service					
Generation		$ 4,799,488	$ 4,798,988	1/	7.13
Generation Related Transmission		265,202	265,202		7.13
General and Common Plant		83,076	83,076		7.13
Land and Land Rights		42,494	42,494		7.13
Intangibles		47,373	47,373		7.13
Helms Regulatory Asset		14,593	14,593		7.13
Total Plant Investment		5,252,226	5,251,726		
Reserves for Depreciation					
Accumulated Provision		(2,367,903)	(2,367,903)		
Decommissioning Accrual		(114,066)	(114,066)		
Total reserves for Depreciation		(2,481,969)	(2,481,969)		
Net Plant in Service		2,770,257	2,769,757		7.13

1. Adjusted for the $500,000 PG&E did not contest with the auditors.

Southern California Edison Company
Net Book Value
(Dollars in Thousands)

DESCRIPTION		Requested Sunk Costs December 31, 1995	Adopted Sunk Costs at December 31, 1995		Rate of Return in Percent
Plant in Service					
Generation		$ 2,832,717	$ 2,832,717		7.22
Generation Related Transmission		48,728	48,728		7.22
General and Common Plant		42,929	42,929		7.22
Land and Land Rights		18,777	18,777		7.22
Intangibles		6,344	6,344		7.22
Total Plant Investment		2,949,495	2,949,495		
Reserves for Depreciation		(1,876,714)	(1,867,407)		
Net Plant in Service		1,072,781	1,082,088		7.22

San Diego Gas and Electric Company
Net Book Value
(Dollars in Thousands)

DESCRIPTION		Requested Sunk Costs December 31, 1995	Adopted Sunk Costs at December 31, 1995		Rate of Return in Percent
Plant in Service					
Generation		$ 429,532	$ 429,532		6.75
Generation Related Transmission		5,772	5,772		6.75
General and Common Plant		4,388	4,388		6.75
Land and Land Rights		5,844	5,844		6.75
Intangibles		168	168		6.75
Other		16	16		
Total Plant Investment		445,720	445,720		
Reserves for Depreciation		(315,812)	(315,812)		
Net Plant in Service		129,908	129,908		6.75

ATTACHMENT 4

TRANSITION COST ELIGIBILITY DETERMINATION

FOR PG&E, EDISON, AND SDG&E

	Description	Eligibility Yes	No	Mixed	Regulatory Treatment	Required Action	Comments	Rate of Return
1	Materials and Supplies (M&S) - All	x			Pre-1998 eligible and Post-1998 are going forward costs.	Physical inventory and market valuation by 12/31/97 or deem book value equal market value at 12/31/97.	This should be filed with appraisal application by 3/2/98.	0
2	Fuel Inventories							
	Oil -PG&E//SDG&E			x	Transition cost Eligibility deferred.	Defer to ISO	None	Carrying cost for 1998 only.
	Oil - Edison			x	Transition cost Eligibility deferred.	File proposal for the treatment of associated revenues by 3/2/98	This should be filed with appraisal application by 3/2/98.	Carrying cost for 1998 only.
	Gas Inventory - Edison	x			Same as M&S	Physical inventory and market valuation by 12/31/97 or book value can be deemed equal to market value at 12/31/97.	This should be filed with appraisal application by 3/2/98.	0
	Coal Inventory - Edison	x			Same as M&S	Same as above.	Possible workshop Ruling to determine transition cost recovery.	0
3	Non-Nuclear Decommissioning Costs Environmental	x			Utilities retain existing liability forecasts.	(1) Rate base offset until 12/31/2001 (2) Amortize 48 months starting 1/1/98 (3) Net present value beginning 2002.	None	0
	Non-Nuclear Decommissioning Costs Non-Environmental	x			Should be captured in divestiture. Until the amortize on current schedule .	None	None	0
4	Construction Work in Progress (CWIP) - 1995			x	Addressed in capital addition proceedings or include as part of market valuation.	None	None	Not Applicable
5	Common and General Plant							
	On-Site	x			Amortize 12/31/95 recorded amounts less offsites.	None	None	Edison - 7.22%, PG&E- 7.13%, SDG&E - 6.75
	Off-Site		x		None	None	Available for other uses or demonstrate not so in a future proceeding.	Not Applicable
6	Emission Credits	x			Credit to TCBA	None	None	Not Applicable
7	Land at Powerplant Sites							
	PG&E	x			To be determined upon final market valuation.	None	None	7.13%
	Edison			x	(1) Functionalize all land, (2) Amortize divested land, (3) Propose treatment for fuel inventory land.	Market value and credit the difference to the TCBA at the date of divestiture.	Include functionalization information with 3/2/98 filing	7.22%
8	Step-up Trans. and Gen. Ties	x			Add to the book value of associated assets.	None	None	Equal to reduced ROR of associated assets.
9	Nuclear Generation Transition Costs							
	ICIP Diablo	x			Incremental Cost Incentive Pricing (ICIP) less market clearing price.	None	None	7.13%
	ICIP SONGS (2&3)	x			Same as Above	None	None	7.35%
	SONGS Upgrade		x		Capacity restricted to adopted benchmark.	None	None	Not Applicable
	Palo Verde Incremental Costs	x			Incremental cost as bills less market clearing price	None	None	7.35%

ATTACHMENT 4
TRANSITION COST ELIGIBILITY DETERMINATION
FOR PG&E, EDISON, AND SDG&E

Description	Eligibility Yes	No	Mixed	Regulatory Treatment	Required Action	Comments	Rate of Return
10 Fuel and Fuel Transportation							
PG&E/SDG&E		x		These are going forward costs.	None	None	Not Applicable
Edison	x			Limited to portion of costs not recovered from market revenues arising from the uneconomic fixed portion of fuel and fuel transportation contracts.	None	Edison shall seek incurred costs in the annual TC proceeding.	0
11 QF Contracts	x			As incurred, contract price compared to market clearing price	None	May be impacted by restructuring/buyouts addressed in a separate proceeding.	0
12 Interutility Contracts	x			Same as for QF	None	None	0
13 Hydroelectric and Geotherm	x			Credit excess revenues beyond the revenue requirement to the TCBA.	None	None	Edison - 7.22%, PG&E- 7.13%
Hydro-relicensing - Past		x		Should be included in market valuation.	None	None	AFUDC Rate
Punped Storage			x	Complete ratemaking determination deferred to A96-07-009	None	None	Reduced ROR
14 Regulatory Assets/Liabilities							
Workers' Compensation - PG&E		x		Going forward costs.	None	No bright line between pre and post 1998.	Not Applicable
Long Term Disability - PG&E			x	Pre 1998 is eligible and post 1998 are going forward costs.	None	None	No TCBA Interest
Post-Retirement Benefits - Edison			x	Same as Above	None	None	No TCBA Interest
PBOPS/Trans. Benefit Oblig.- All			x	Pre 1998 is eligible and post 1998 are going forward costs.	None	None	No TCBA Interest
Pension/Trans. Benefit Oblig. - All		x		Regulatory liability should be used to offset TBO regulatory asset and any excess to TCBA.	None	None	No TCBA Interest
Environmental Compliance		x		None	None	Seek eligibility after costs are incurred.	Not Applicable
Gain or loss on reacquired debt			x	Pre 1998 is ineligible and post 1998 are eligible.		Seek recovery if/when incurred.	0
15 Deferred Taxes	x			Amortize tax receivables and payables to zero by the end of the transition period.	None		0
16 Balancing Accounts							
ECAC and ERAM	x			ECAC under/over collections	None	None	0
17 WAPA - PG&E	x			True-up in annual transition cost proceeding	None	None	0
18 QF Buyouts - PG&E	x			Record in the TCBA when approved.	Track in a memo account.	None	0

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. (U 39 E)	)	Application No. 96-08-001 (Filed August 1, 1996)
And Consolidated Proceedings	)	A. 96-08-006 A. 96-08-007
Application of Pacific Gas and Electric Company To Establish the Competition Transition Charge (U 39 E)	)	Application 96-08-070 (Supplemented October 21,1996)
And Consolidated Proceedings	)	A. 96-08-071 A. 96-08-072

CTC PHASE 2
JOINT PROPOSAL AND EXHIBIT ON TAX RELATED ISSUES
SPONSORED BY ORA, TURN, SCE, SDG&E AND PG&E

I <u>Purpose</u>

During Phase 2 of the CTC proceeding, it became apparent that many of the perceived tax disputes raised by parties in their testimony were in fact due to misinterpretations brought about by complex and technical tax jargon used differently by the different parties, rather than arising from any fundamental dispute.

Thus, the participants in this workshop have set out to produce this joint exhibit to highlight areas of agreement, and to draw from each utility's Competition Transition Charge (CTC) filing[1] to provide clear and concise numeric presentations[2] that demonstrate how, and to whom (ratepayers or utilities), tax costs or benefits should flow during the CTC period.

All involved hope that this exhibit will help to avoid time-consuming, expensive, and counterproductive litigation of tax issues in the CTC hearings, where other important issues exist to occupy the parties.

2 Workshop Record

Representatives from Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) met with representatives from the Office of Ratepayer Advocates (ORA) and The Utility Reform Network (TURN). Meetings were held on May 16th, May 28th, June 4th, and June 9th of this year. In addition, phone conferences were held between various parties. While not every representative participated in every session, the participants have all reached consensus on how taxes should be accounted for in the CTC process. That accord is manifested solely in this document.

[1] A 96-08-070, filed October 21, 1996 for PG&E; A 96-08-071, filed October 21, 1996, as revised February, 1997 for SCE; A 96-08-072, filed October 21, 1996 for SDG&E.
[2] From CTC workpapers; estimated balances as of January 1, 1998; these amounts were audited during the Sunk Cost Audit.

3 Consensus Regarding CTC Accounting for Taxes

Goals

3.1 One of the goals inherent in the Preferred Policy Decision (PPD) and AB 1890 is the full satisfaction of all obligations between ratepayers and investor owned utilities during the CTC period, unless the obligation is specifically excluded, or recovery is statutorily limited.

3.2 To this end, the PPD and AB 1890 accelerate the recovery of remaining above market plant costs and other generation-related costs, including regulatory assets, during the four year CTC transition period, subject to the statutory limitations of a rate freeze and fixed recovery period. There should be an appropriate sharing of benefits and costs between ratepayers and utilities during the CTC period resulting in full satisfaction of non-excluded obligations, and a "clean slate" between ratepayers and utilities thereafter as utility generation competes in the competitive market.

Guidance

3.3 As noted above, the PPD and AB 1890 are the principal sources of authority to determine the industry restructuring goals and limitations that provide a backdrop for sharing tax benefits and tax costs between ratepayers and utilities. Decisions adopted by the Commission during the course of the CTC proceedings will implement the AB 1890 goals and limitations.

3.4 In addition, Internal Revenue Service (IRS) normalization rules contained in the Internal Revenue Code (IRC) should not be disregarded because the severe penalties that would be imposed by the IRS due to a violation would significantly increase ratepayer costs during the transition period. Similarly, other IRC provisions and state tax laws are governing.

3.5 Finally, Financial Accounting Standards Board (FASB) pronouncements also provide guidance. Although the Commission is not bound by these accounting standards, the standards provide valuable direction because they represent the consensus conclusion of a panel of accounting experts reached after thorough and open debate. These conclusions provide a useful framework for recognizing costs and matching costs with benefits. In addition, the same tax-related FASB pronouncements bind non-regulated generators today and will bind the utilities in the same manner after the CTC transition period.

Stipulations

3.6 This agreement addresses property-related taxes (including "tax-on-tax" gross-ups), PG&E's vacation pay deferred tax asset, and SCE's ad valorem lien date tax asset. This agreement does not address or govern any tax or accounting issues arising from other non-property related taxation, such as Post Retirement Benefits other than Pensions (PBOP's) or Pensions.

3.7 The parties agree that CTC Tax Costs (Regulatory Tax Receivables) are fully eligible for recovery during the CTC transition period. Thus, the utilities will have the opportunity to receive full funding for CTC Tax Costs subject only to the statutory limitations (rate freeze and a fixed recovery period) imposed by AB 1890. CTC Tax Costs for property related items are determined as follows[3]:

A. (+ Net Book Value of generation-related plant

- Net Tax Value)

* Applicable Statutory Tax Rate [federal and state]

* Net to Gross Multiplier for Taxes

B. - (Deferred Tax Reserve for normalized property[4],

* Net to Gross Multiplier for Taxes).

3.8 The CTC Revenue Requirement will continue to be adjusted by the amount of revenue requirement associated with a return[5] computed on the Deferred Tax Reserve balance (before gross up) related to taxes on normalized property until the end of the CTC transition period.

3.9 As the CTC Tax Costs related to flow-through property are funded[6] during the CTC transition period, the CTC Revenue Requirement will be adjusted for the amount of revenue requirement associated with a return on the

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[3] This computation is demonstrated in the Appendices attached for each utility, and is incorporated herein by this reference.

[4] This provides ratepayers with a credit for Deferred Taxes previously funded by them.

[5] Return is determined by the appropriate rate of return times the base amount. The appropriate rate of return is either the utility's authorized rate of return, or the reduced rate of return provided for in AB 1890 when a utility accelerates recovery of uneconomic costs, as applicable.

[6] The Minkin Proposed Decision provides for ordering of recovery based on the rate-of-return earned by the various assets, while the Conlon Proposed Decision requires level amortization over 48 months. In either case, the Deferred Tax Reserve related to flow-through taxes will increase or decrease as a function of the pattern of amortization of the regulatory asset or liability and the level of current taxes paid to taxing authorities.

funded Deferred Tax Reserve balance (related to taxes on flow-through property) until the end of the CTC transition period[7].

3.10 All property-related regulatory tax receivables and/or payables will be amortized to zero by the end of the CTC transition period. This will settle all property-related tax benefits or obligations between ratepayers and utilities. No further sharing of benefits or obligations will occur beyond the end of the CTC transition period, except as provided for in the decisions relating to the Diablo Canyon, Palo Verde, and San Onofre nuclear plants.

3.11 PG&E ratepayers will continue to receive a credit against the CTC Revenue Requirement for the amount of revenue requirement associated with a return on the Unamortized Investment Tax Credit (ITC) balance, as permitted by IRC Section 46(f)(1), during the CTC period.

3.12 SCE and SDG&E ratepayers will continue to receive a credit against the CTC Revenue Requirement for the amount of the revenue requirement associated with the amortization of ITC, as permitted by IRC Section 46(f)(2), during the CTC period.

3.13 SCE's Regulatory Tax Asset related to the Ad Valorem Lien Date Adjustment will be treated as follows:

- During the first three years of the CTC period, or until the property generating the ad valorem lien date adjustment is sold, whichever comes first, the ad valorem lien date regulatory receivable will be

[7] Traditionally, the Regulatory Asset and the Deferred Tax Liability have been of equal but opposite amounts. During the CTC period, this relationship will be decoupled as the Regulatory Receivable will be recovered over the CTC period, but the Deferred Tax Liability will unwind naturally. This will have the effect of funding the deferred tax over the CTC period. This funded amount (Regulatory Receivable - Deferred Tax Liability) will earn or pay a return which will be included in the CTC Revenue Requirement.

adjusted annually using the method contained in SCE's CTC workpapers. That is, tax benefits for ad valorem taxes will continue to be flowed through to ratepayers in advance of payment of the tax. The cumulative amount of this benefit, which is reflected in the tax regulatory asset, will change annually based upon the property tax due and the benefits provided to ratepayers.

- If a plant is sold or divested, the ad valorem lien date regulatory tax asset related to that plant will be included in the gain on sale computation and will be fully recoverable from ratepayers at that time.
- To the extent the ad valorem lien date regulatory tax asset has not been recovered on or before January 1, 2001, it will be recoverable in full from ratepayers in that year or in the last year of the CTC period if that occurs earlier.

3.14 PG&E's Vacation Pay Deferred Tax Asset will not be amortized during the CTC transition period. However, PG&E will continue to increase the CTC Revenue Requirement for the amount of the revenue requirement associated with a return on the Vacation Pay Deferred Tax Asset, as adjusted for the impact of asset sales or market valuations.

3.15 This agreement formally and with finality concludes and resolves all property-related tax issues raised by and between the workshop participants[8]. The participants ask the Commission to give this document favorable weight in determining the outcome of these issues.

4 <u>Accounting Presentation from Each Utility</u>

Attached are summaries of the plant and tax amounts, as of January 1, 1998, that will be recovered by each utility or credited to ratepayers, subject to Commission approval. Note that these are estimated amounts from each utility's

[8] The workshop participants included all who raised property-related tax issues during the CTC proceeding to date. In addition, ALJ Minkin announced the start of the workshop, and extended an invitation to all interested parties to attend.

CTC filing; actual amounts as of January 1, 1998, will be based on the books of account of each utility and provisions of Commission decisions resolving disputed issues related to the CTC treatment of underlying property, and will likely be different from the forecast amounts. Also attached is an appendix containing definitions agreed upon by the participants.

5 Conclusion

The participants believe that the goals of the PPD and AB 1890 are met through the tax accounting detailed above. The accounting fairly shares benefits and costs during the CTC transition period, concludes obligations between ratepayers and utilities at the end of the CTC period, and at all times accommodates requirements imposed by taxing authorities and others.

CTC Tax Workshop
Pacific Gas & Electric Company
Non-Nuclear Generation Regulatory Receivable for Taxes - Property Related

Total Non-Nuclear		
Net Book Value at January 1, 1998		$ 2,629,525,000
Net Book Value Tax Gross up:		
Net Book Value	2,629,525,000	
Remaining State Tax Basis *	(1,064,447,000)	
Net Excess Includable in Taxable Income	1,565,078,000	
State Tax Rate	8.840%	
State Tax Differences Before Gross Up	138,352,895	
Net to Gross Multiplier for Taxes	1.68765	
Deferred Tax Liability (due from ratepayers)		233,491,263
Net Book Value Tax Gross up:		
Net Book Value	2,629,525,000	
Remaining Federal Tax Basis	(1,064,447,000)	
State Tax Differences Before Gross Up	(138,352,895)	
Net Excess Includable in Taxable Income	1,426,725,105	
Federal Tax Rate	35.000%	
Net to Gross Multiplier for Taxes	1.68765	
Deferred Tax Liability (due from ratepayers)		842,734,418
Normalized Deferred Tax Reserve:		
ACRS/MACRS Deferred Tax **	273,108,000	
Net to Gross Multiplier for Taxes	1.68765	
Total (credit to ratepayers)		(460,910,716)
Deferred ITC:		
Unamortized ITC		See page 6
Return on Unamortized ITC balance (per IRC 46(f)(1))		See page 6
Net to Gross Multiplier for Taxes		See page 6
Total (credit to ratepayers)		(28,210,064)
CTC Revenue Requirement before Valuation		3,216,629,901
Less Valuation ***		0
Net CTC Revenue Requirement		3,216,629,901
Net Book Value		(2,629,525,000)
Net CTC Revenue Requirement for Taxes		587,104,901

* PG&E used a combined tax rate in its forecast to estimate the state tax liability.

** Amount includes ARAM. If the plant was sold or valued at an amount other than zero, a portion of this would be retained by PG&E in accordance with Internal Revenue Code normalization rules.

*** For purposes of this computation, pending actual valuation or sale, the valuation has been assumed to be zero.

CTC Tax Workshop
Pacific Gas & Electric Company
Non-Nuclear Generation Regulatory Receivable for Taxes - Property Related

Fossil		
Net Book Value at January 1, 1998		$ 827,137,000
Net Book Value Tax Gross up:		
Net Book Value	827,137,000	
Remaining State Tax Basis *	(496,447,000)	
Net Excess Includable in Taxable Income	330,690,000	
State Tax Rate	8.840%	
State Tax Differences Before Gross Up	29,232,996	
Net to Gross Multiplier for Taxes	1.68765	
Deferred Tax Liability (due from ratepayers)		49,335,066
Net Book Value Tax Gross up:		
Net Book Value	827,137,000	
Remaining Federal Tax Basis	(496,447,000)	
State Tax Differences Before Gross Up	(29,232,996)	
Net Excess Includable in Taxable Income	301,457,004	
Federal Tax Rate	35.000%	
Net to Gross Multiplier for Taxes	1.68765	
Deferred Tax Liability (due from ratepayers)		178,063,869
Normalized Deferred Tax Reserve:		
ACRS/MACRS Deferred Tax **	29,110,000	
Net to Gross Multiplier for Taxes	1.68765	
Total (credit to ratepayers)		(49,127,492)
Deferred ITC:		
Unamortized ITC		See page 6
Return on Unamortized ITC balance (per IRC 46(f)(1))		See page 6
Net to Gross Multiplier for Taxes		See page 6
Total (credit to ratepayers)		(10,299,893)
CTC Revenue Requirement before Valuation		995,108,550
Less Valuation ***		0
Net CTC Revenue Requirement		995,108,550
Net Book Value		(827,137,000)
Net CTC Revenue Requirement for Taxes		167,971,550

* PG&E used a combined tax rate in its forecast to estimate the state tax liability.

** Amount includes ARAM. If the plant was sold or valued at an amount other than zero, a portion of this would be retained by PG&E in accordance with Internal Revenue Code normalization rules.

*** For purposes of this computation, pending actual valuation or sale, the valuation has been assumed to be zero.

CTC Tax Workshop
Pacific Gas & Electric Company
Non-Nuclear Generation Regulatory Receivable for Taxes - Property Related

Geothermal		
Net Book Value at January 1, 1998		$ 341,890,000
Net Book Value Tax Gross up:		
Net Book Value	341,890,000	
Remaining State Tax Basis *	(107,765,000)	
Net Excess Includable in Taxable Income	234,125,000	
State Tax Rate	8.840%	
State Tax Differences Before Gross Up	20,696,650	
Net to Gross Multiplier for Taxes	1.68765	
Deferred Tax Liability (due from ratepayers)		34,928,701
Net Book Value Tax Gross up:		
Net Book Value	341,890,000	
Remaining Federal Tax Basis	(107,765,000)	
State Tax Differences Before Gross Up	(20,696,650)	
Net Excess Includable in Taxable Income	213,428,350	
Federal Tax Rate	35.000%	
Net to Gross Multiplier for Taxes	1.68765	
Deferred Tax Liability (due from ratepayers)		126,067,324
Normalized Deferred Tax Reserve:		
ACRS/MACRS Deferred Tax **	43,275,000	
Net to Gross Multiplier for Taxes	1.68765	
Total (credit to ratepayers)		(73,033,054)
Deferred ITC:		
Unamortized ITC		See page 6
Return on Unamortized ITC balance (per IRC 46(f)(1))		See page 6
Net to Gross Multiplier for Taxes		See page 6
Total (credit to ratepayers)		(4,610,790)
CTC Revenue Requirement before Valuation		425,242,181
Less Valuation ***		0
Net CTC Revenue Requirement		425,242,181
Net Book Value		(341,890,000)
Net CTC Revenue Requirement for Taxes		83,352,181

* PG&E used a combined tax rate in its forecast to estimate the state tax liability.

** Amount includes ARAM. If the plant was sold or valued at an amount other than zero, a portion of this would be retained by PG&E in accordance with Internal Revenue Code normalization rules.

*** For purposes of this computation, pending actual valuation or sale, the valuation has been assumed to be zero.

CTC Tax Workshop
Pacific Gas & Electric Company
Non-Nuclear Generation Regulatory Receivable for Taxes - Property Related

Hydro		
Net Book Value at January 1, 1998		$ 822,270,000
Net Book Value Tax Gross up:		
Net Book Value	822,270,000	
Remaining State Tax Basis *	(407,736,000)	
Net Excess Includable in Taxable Income	414,534,000	
State Tax Rate	8.840%	
State Tax Differences Before Gross Up	36,644,806	
Net to Gross Multiplier for Taxes	1.68765	
Deferred Tax Liability (due from ratepayers)		61,843,607
Net Book Value Tax Gross up:		
Net Book Value	822,270,000	
Remaining Federal Tax Basis	(407,736,000)	
State Tax Differences Before Gross Up	(36,644,806)	
Net Excess Includable in Taxable Income	377,889,194	
Federal Tax Rate	35.000%	
Net to Gross Multiplier for Taxes	1.68765	
Deferred Tax Liability (due from ratepayers)		223,210,644
Normalized Deferred Tax Reserve:		
ACRS/MACRS Deferred Tax **	64,233,000	
Net to Gross Multiplier for Taxes	1.68765	
Total (credit to ratepayers)		(108,402,822)
Deferred ITC:		
Unamortized ITC		See page 6
Return on Unamortized ITC balance (per IRC 46(f)(1))		See page 6
Net to Gross Multiplier for Taxes		See page 6
Total (credit to ratepayers)		(9,046,645)
CTC Revenue Requirement before Valuation		989,874,784
Less Valuation ***		0
Net CTC Revenue Requirement		989,874,784
Net Book Value		(822,270,000)
Net CTC Revenue Requirement for Taxes		167,604,784

* PG&E used a combined tax rate in its forecast to estimate the state tax liability. For Hydro, a rate of 9.3% was used in the filing. Here, the rate has been corrected to 8.84%, lowering tax costs.

** Amount includes ARAM. If the plant was sold or valued at an amount other than zero, a portion of this would be retained by PG&E in accordance with Internal Revenue Code normalization rules.

*** For purposes of this computation, pending actual valuation or sale, the valuation has been assumed to be zero.

CTC Tax Workshop
Pacific Gas & Electric Company
Non-Nuclear Generation Regulatory Receivable for Taxes - Property Related

Helms		
Net Book Value at January 1, 1998		$ 638,228,000
Net Book Value Tax Gross up:		
Net Book Value	638,228,000	
Remaining State Tax Basis *	(52,499,000)	
Net Excess Includable in Taxable Income	585,729,000	
State Tax Rate	8.840%	
State Tax Differences Before Gross Up	51,778,444	
Net to Gross Multiplier for Taxes	1.68765	
Deferred Tax Liability (due from ratepayers)		87,383,891
Net Book Value Tax Gross up:		
Net Book Value	638,228,000	
Remaining Federal Tax Basis	(52,499,000)	
State Tax Differences Before Gross Up	(51,778,444)	
Net Excess Includable in Taxable Income	533,950,556	
Federal Tax Rate	35.000%	
Net to Gross Multiplier for Taxes	1.68765	
Deferred Tax Liability (due from ratepayers)		315,392,580
Normalized Deferred Tax Reserve:		
ACRS/MACRS Deferred Tax **	136,490,000	
Net to Gross Multiplier for Taxes	1.68765	
Total (credit to ratepayers)		(230,347,349)
Deferred ITC:		
Unamortized ITC		See page 6
Return on Unamortized ITC balance (per IRC 46(f)(1))		See page 6
Net to Gross Multiplier for Taxes		See page 6
Total (credit to ratepayers)		(4,252,736)
CTC Revenue Requirement before Valuation		806,404,386
Less Valuation ***		0
Net CTC Revenue Requirement		806,404,386
Net Book Value		(638,228,000)
Net CTC Revenue Requirement for Taxes		168,176,386

* PG&E used a combined tax rate in its forecast to estimate the state tax liability.

** Amount includes ARAM. If the plant was sold or valued at an amount other than zero, a portion of this would be retained by PG&E in accordance with Internal Revenue Code normalization rules.

*** For purposes of this computation, pending actual valuation or sale, the valuation has been assumed to be zero.

CTC Tax Workshop
Pacific Gas & Electric Company
Non-Nuclear Generation Regulatory Receivable for Taxes - Property Related

Weighted Average ITC

From CTC WP	1998	1999	2000	2001	Total
Fossil	$ 23,421,000	22,272,000	21,122,000	19,973,000	
Geothermal	10,486,000	9,971,000	9,455,000	8,939,000	
Hydro	20,567,000	19,560,000	18,553,000	17,548,000	
Helms	9,365,000	9,094,000	8,823,000	8,552,000	
	63,839,000	60,897,000	57,953,000	55,012,000	

46(f)(1) Calculation	1998	1999	2000	2001	Total
Fossil	$ 23,421,000	$ 22,272,000	$ 21,122,000	$ 19,973,000	
Rate of Return *	9.45%	9.45%	9.45%	9.45%	
Return Net-to-Gross Multiplier **	1.25586	1.25586	1.25586	1.25586	
Credit to Return ***	2,779,575	2,643,214	2,506,733	2,370,371	10,299,893
Geothermal	$ 10,486,000	$ 9,971,000	$ 9,455,000	$ 8,939,000	
Rate of Return	9.45%	9.45%	9.45%	9.45%	
Return Net-to-Gross Multiplier	1.25586	1.25586	1.25586	1.25586	
Credit to Return	1,244,466	1,183,346	1,122,108	1,060,870	4,610,790
Hydro	$ 20,567,000	$ 19,560,000	$ 18,553,000	$ 17,548,000	
Rate of Return	9.45%	9.45%	9.45%	9.45%	
Return Net-to-Gross Multiplier	1.25586	1.25586	1.25586	1.25586	
Credit to Return	2,440,866	2,321,357	2,201,847	2,082,575	9,046,645
Helms	$ 9,365,000	$ 9,094,000	$ 8,823,000	$ 8,552,000	
Rate of Return	9.45%	9.45%	9.45%	9.45%	
Return Net-to-Gross Multiplier	1.25586	1.25586	1.25586	1.25586	
Credit to Return	1,111,427	1,079,265	1,047,103	1,014,941	4,252,736
				Total	28,210,064

* Estimated Rate of Return; the actual rate used during the CTC period will be different, and normally is stated with the equity grossup included.

** Only the equity component in the rate of return requires a gross-up. Here, current statutory tax rates are used with an assumed debt/equity ratio of 50% to develop this estimate; the actual gross up rate will vary.

*** For purposes of this exhibit, return is not included, and only this ITC adjustment to return is shown.

CTC Tax Workshop
Southern California Edison
Non-Nuclear Generation Regulatory Receivable for Taxes - Summary

$ IN THOUSANDS

Regulatory Tax Receivable - Non-nuclear Generation	
Property Related	$9,003
Ad Valorem Lien Date	3,738
Investment Tax Credit	(14,775)
Total	($2,034)
Deferred Investment Tax Credit	($25,096)

CTC Tax Workshop
Southern California Edison
Non-Nuclear Generation Regulatory Receivable for Taxes - Property Related

Net Book Value at January 1, 1998		1,104,487,000
Net Book Value Tax Gross up:		
Net Book Value	1,104,487,000	
Remaining State Tax Basis	(921,569,000)	
Net	182,918,000	
Apportioned State Tax Rate	8.53980%	
Net to Gross Multiplier for Taxes	1.68211	
Total		26,275,957
Net Book Value	1,104,487,000	
Remaining Federal Tax Basis	(747,602,000)	
State Tax Differences before Gross Up *	(15,620,831)	
Net	341,264,169	
Federal Tax Rate	35%	
Net to Gross Multiplier for Taxes	1.68211	
Total		200,915,355
Normalized Deferred Tax Reserve:		
ACRS / MACRS Deferred Tax **	134,592,000	
Unicap Deferred Tax	(4,881,000)	
Normalized Taxes	129,711,000	
Net to Gross Multiplier for Taxes	1.68211	
Total		(218,188,170)
CTC Revenue Requirement before Valuation		1,113,490,142
Less Valuation ***		0
Net CTC Revenue Requirement		1,113,490,142
Net Book Value		(1,104,487,000)
Net CTC Revenue Requirement for Taxes		9,003,142

This schedule does not include amounts related to Hydro.

* Amount is computed as $182,918,000 * 8.5398%

** Amount includes ARAM. If the plant was sold or valued at an amount other than zero, a portion of this would not be available to ratepayers in compliance with the Internal Revenue Code normalization rules.

*** For purposes of this computation, pending actual valuation or sale, the valuation has been assumed to be zero.

CTC Tax Workshop
Southern California Edison
Non-Nuclear Generation Regulatory Receivable for Taxes - Ad Valorem Lien Date

Timing Difference - Ad Valorem Taxes		
Lien Date Adjustment - Non-Nuclear	5,480,000	
Apportioned Tax Rate	40.55087%	
Net to Gross Multiplier for Taxes	1.68211	
Total		3,737,964
Normalized Deferred Tax Reserve:		
Normalized Taxes	0	
Net to Gross Multiplier for Taxes	1.68211	
Total		0
CTC Revenue Requirement		3,737,964

This schedule does not include amounts related to Hydro.

CTC Tax Workshop
Southern California Edison
Non-Nuclear Generation Regulatory Receivable for Taxes - Investment Tax Credit

Investment Tax Credit		
Deferred ITC - Non-Nuclear at 1/1/98	(25,096,000)	
Federal Tax Rate	35%	
Net to Gross Multiplier for Taxes	1.68211	
Total		(14,774,981)
Normalized Deferred Tax Reserve:		
Normalized Taxes	0	
Net to Gross Multiplier for Taxes	1.68211	
Total		0
CTC Revenue Requirement *		(14,774,981)

This schedule does not include amounts related to Hydro.

* Only the gross-up related to ITC is included with the Regulatory Assets for Taxes; the Deferred ITC itself was separately listed. If the plant is sold or is valued at an amount other than zero, a portion of this would not be available to ratepayers in compliance with the Internal Revenue Code normalization rules.

Application No: 96-08-071
Exhibit No: SCE-11A
(Update to SCE-11)
Witness: D. J. Klun

SOUTHERN CALIFORNIA
EDISON

An *EDISON INTERNATIONAL* Company

(U 338-E)

Update To Transition Costs For Regulatory Assets, Obligations, And Balancing Accounts

Before the
Public Utilities Commission of the State of California

Rosemead, California
February 1997

REGULATORY ASSETS-NUCLEAR GENERATION
DECEMBER 31, 1997 THROUGH 2001

DESCRIPTION	12/31/95 Nuclear Generation	1996 Activity	12/31/96 Balance	Tax Rate Change	Adj. 12/31/96 Balance	1997 Activity	1/1/98 Balance	1998 Activity	12/31/98 Balance
UNREALIZED GAIN/LOSS ACE/EXEL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UNREALIZED GAIN/LOSS ACE/EXEL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ENVEST STARTUP COSTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ETC-FERC-COOLWATER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ACE LIMITED INSURANCE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AD VALOREM LIEN DATE-GAS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AD VALOREM LIEN DATE-WATER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ACCRUED VACATION	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AD VALOREM LIEN DATE-ELECTRIC	17,877,264.29	(3,066,800.57)	14,810,463.72	(299,932.60)	14,510,531.12	(1,693,679.72)	12,816,861.40	(2,667,733.15)	10,149,118.25
UNREALIZED HOLDING GAINS/LOSSES	(11,708,068.01)	(62,696,340.43)	(74,404,308.44)	2,103,267.86	(72,301,040.58)	0.00	(72,301,040.59)	0.00	(72,301,040.59)
INVESTMENT IN EXCESS OF COST	11,708,068.01	62,696,340.43	74,404,308.44	(2,103,267.86)	72,301,040.60	0.00	72,301,040.59	0.00	72,301,040.59
INSURANCE RESERVE/CASUALTY LOSSES	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CIAC - DEFERRED REVENUE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DECOMM CONTRIBUTION - NON-QUAL	(74,959,387.00)	2,470,585.96	(72,488,801.05)	1,467,961.82	(71,020,860.02)	(2,076,981.37)	(73,097,841.40)	(2,076,981.37)	(75,074,822.77)
DECOMMISSIONING TRUST EARN-NQ BOOK	4,690,421.18	3,753,396.30	8,443,817.48	(170,993.52)	8,272,823.96	2,402,888.51	10,675,712.47	2,006,676.34	12,782,388.81
PBOP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HAZARDOUS WASTE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UNCOLLECTIBLE ACCTS - OAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DOE DECONTAMINATION	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DECOMMISSIONING TRUST EARN-NQ TAX	(3,033,667.69)	(9,144,598.37)	(12,178,264.06)	101,236.40	(12,077,029.59)	(5,926,615.17)	(18,002,644.76)	(6,428,163.79)	(24,430,808.55)
UNCOLLECTIBLE ACCOUNTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PROPERTY RELATED ITEMS	894,308,000.00	(88,711,000.00)	806,196,000.00	(24,299,000.00)	781,897,000.00	(217,399,000.00)	564,498,000.00	(251,989,000.00)	312,509,000.00
DEFERRED ITC ITEMS	(107,768,993.00)	9,204,308.00	(98,564,685.00)	819,275.00	(97,745,310.00)	15,574,878.00	(82,170,432.00)	20,632,255.00	(61,538,177.00)
	731,711,727.19	(95,494,098.09)	646,217,628.89	(22,380,462.04)	623,837,196.48	(209,375,519.78)	413,961,646.71	(249,022,964.97)	172,938,698.74

Account 182.379 ARAM is included in the normal deferred taxes.

RGAS1.WK4

REGULATORY ASSETS - NON-NUCLEAR GENERATION
DECEMBER 31, 1997 THROUGH 2001

ACCOUNT NUMBER	DESCRIPTION	12/31/96 Non-Nuclear Gen	1996 Activity	12/31/96 Balance	Tax Rate Change	Adj.12/31/96 Balance	1997 Activity	1/1/98 Balance	1998 Activity	12/31/98 Balance
182,225	UNREALIZED GAIN/LOSS ACE/EXEL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182,226	UNREALIZED GAIN/LOSS ACE/EXEL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182,300	ENVEST STARTUP COSTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182,307	ETC-FERC-COOLWATER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182,310	ACE LIMITED INSURANCE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182,311	AD VALOREM LIEN DATE-GAS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182,312	AD VALOREM LIEN DATE-WATER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182,313	ACCRUED VACATION	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182,314	AD VALOREM LIEN DATE-ELECTRIC	3,266,220.14	616,841.16	3,882,061.30	(78,614.61)	3,803,446.69	(66,482.58)	3,737,964.11	22,509.64	3,760,473.75
182,316	UNREALIZED HOLDING GAINS/LOSSES	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182,317	INVESTMENT IN EXCESS OF COST	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182,319	INSURANCE RESERVE/CASUALTY LOSSES	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182,321	CIAC - DEFERRED REVENUE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182,322	DECOMM NET EARN-NON-QUAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182,326	DECOMMISSIONING TRUST-NQ BOOK	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182,331	PBOP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182,332	HAZARDOUS WASTE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182,343	UNCOLLECTIBLE ACCTS - OAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182,359	DOE DECONTAMINATION	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182,365	DECOMMISSIONING TRUST-NQ EXPENSE	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
182,366	UNCOLLECTIBLE ACCOUNTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	PROPERTY RELATED ITEMS	25,036,000.00	(6,405,000.00)	18,631,000.00	(1,547,000.00)	17,084,000.00	(8,081,000.00)	9,003,000.00	(42,092,000.00)	(33,089,000.00)
	DEFERRED ITC ITEMS	(17,201,826.00)	1,194,470.00	(16,007,356.00)	133,719.00	(15,863,636.00)	1,178,666.00	(14,774,981.00)	3,695,511.00	(11,079,470.00)
		11,019,395.14	(4,593,688.84)	6,425,706.30	(1,491,895.61)	4,933,810.69	(6,967,827.58)	(2,034,016.89)	(38,373,979.36)	(40,407,996.25)

Account 182,379 ARAM is included in the normal deferred taxes.

B-3

RGAS1.WK4

FILE: TX_RTFUT.WK4

Tax Rates

	1997 Statutory Rate	1995 ORC Apportionment Factor	Ratio of State Income To California		Ratemaking Tax Rates
California	8.8400%	93.0762%	100.0000%	8.2279%	8.2279%
Arizona (Note)	8.2569%	2.9878%	95.2655%	0.2350%	0.2350%
New Mexico	7.6000%	1.1776%	85.8768%	0.0769%	0.0769%
Total States				8.5398%	
Federal Statutory Rate				35.0000%	35.0000%
Federal Benefit of State Taxes				2.98893%	-2.98893%
Total					40.55087%

(Note) Rate for Arizona to give effect to deduction of Arizona Income Tax

(A) Statutory Rate	9.0000%
(B) 1 Plus Statutory Rate	109.0000%
Arizona Effective Rate = (A) ÷ (B)	8.2569%

A.96-08-001 et al.

ATTACHMENT 5
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FILE: TX_RTFUT.WK4

Gross-Up Rate

State Composite	8.5398%	8.5398%
Federal Statutory Rate	35.0000%	
Federal Benefit of State Taxes	2.98893%	-2.98893%
Federal Statutory Rate		35.00000%
Total		40.55087%
Gross-Up Rate 1 ÷ (1 - 40.55087%) =		1.682110

CTC TAX WORKSHOP
SAN DIEGO GAS & ELECTRIC
NON-NUCLEAR GENERATION REGULATORY RECEIVABLE FOR TAXES - PROPERTY RELATED

Total Non-Nuclear		
Net Book Value at January 1, 1998		151,866,000
Net Book Value Tax Gross up:		
Net Book Value	151,866,000	
Remaining State Tax Basis	(101,234,086)	
Net	50,631,914	
Apportioned State Tax Rate	8.84%	
Net to Gross Multiplier for Taxes	1.68765	
Total		7,553,686
Net Book Value	151,866,000	
Remaining Federal Tax Basis	(90,964,825)	
State Tax Differences before Gross Up (1)	(4,475,861)	
Net	56,425,314	
Federal Tax Rate	35%	
Net to Gross Multiplier for Taxes	1.68765	
Total		33,329,159
Normalized Deferred Tax Reserve:		
ACRS/MACRS Deferred Tax (2)	5,265,000	
Unicap Deferred Tax	(1,067,000)	
Normalized Taxes	4,198,000	
Net to Gross Multiplier for Taxes	1.68765	
Total		(7,084,754)
Deferred ITC:		
Unamortized ITC (3)	2,550,592	
Net to Gross Multiplier for Taxes	1.68765	
Total		(4,304,506)
CTC Revenue Requirement before Valuation		181,359,585
Less Valuation (4)		0
Net CTC Revenue Requirement		181,359,585
Net Book Value		(151,866,000)
Net CTC Revenue Requirement for Taxes		29,493,585

(1) Amount is computed as $50,631,914 * 9.3%

(2) Amount includes ARAM. If the plant was sold or valued at an amount other than zero, a portion of this would not be available to ratepayers in compliance with the Internal Revenue Code normalization rules.

(3) If the plant is sold or is valued at an amount other than zero, a portion of Deferred ITC would not be available to ratepayers in compliance with the Internal Revenue Code normalization rules.

(4) For purposes of this computation, pending actual valuation or sale, the valuation has been assumed to be zero.

CTC TAX WORKSHOP
APPENDIX TO
JOINT PROPOSAL AND EXHIBIT

1 Definitions

The participants have agreed upon the following definitions:

1.1 DEFERRED TAX LIABILITY (DTL)

Taxes owed by the utilities to taxing authorities. The liability is based on the difference between book and tax basis, after accounting for accumulated book depreciation and accumulated tax depreciation to date. The difference times the applicable tax rate establishes the nominal amount of the liability. The liability generally will not come due immediately, but will be paid over time.

1.2 DEFERRED TAX ASSET (DTA)

Income taxes due from taxing authorities to the utilities. A DTA will usually come about because book treatment is more favorable than the corresponding tax treatment. For example, PG&E's treatment of vacation pay gives rise to a DTA because PG&E funds the taxes due. When a DTA is created, the utilities have paid more in tax today, but will receive future tax deductions that yield a tax benefit later.

1.3 FLOW-THROUGH TAX ACCOUNTING

Under this method of ratemaking, tax expense is included in the test year revenue requirement based on actual cash taxes paid to taxing authorities. Thus, the benefit of accelerated tax depreciation is passed through to ratepayers in the early years of an asset's life, but is repaid in the form of higher rates in the later years of the asset's life. The Commission has adopted flow-through tax accounting for pre-1981 additions to plant, post-1980 differences between book and tax basis, and state taxes.

1.4 NORMALIZED TAX ACCOUNTING[1]

This method of ratemaking sets rates based on tax expense computed as if book depreciation (which is not accelerated) were deductible on tax returns. In effect, ratepayers reimburse utilities for total tax expense, including current and deferred taxes. This increases ratemaking tax expense initially, and gives utilities cash for deferred tax expense in excess of amounts actually paid to tax authorities in the early years of the asset's life. However, in the later years of an asset's life, ratepayers benefit from lower rates because the total tax expense is lower, and the Deferred Tax Reserve is used to pay current taxes due to taxing authorities in excess of the total tax expense recovered in rates.

1.5 DEFERRED TAX RESERVE

For assets subject to normalized tax accounting, ratepayers will pay for a level of tax expense in rates, in the early years of the asset's life, that is higher than the tax expense paid by the utilities to taxing authorities. This extra amount funds a Deferred Tax Reserve that reverses in later years to pay tax expense to taxing authorities that is higher than that collected in

[1] Applies predominantly to life and method timing differences on plant placed-in-service after 1980.

rates. During the existence of the reserve, it is used to lower rate base, thus providing a benefit to ratepayers by lowering the return component of rates.

1.6 REGULATORY ASSET OR RECEIVABLE

Amounts owed by the ratepayers to utilities. As defined above, a DTL can be computed for any asset based on the relative amounts of book and tax depreciation taken to date. If the asset was subject to flow-through tax accounting, the utilities have a regulatory receivable that recognizes that ratepayers have benefited from lower rates in the early years of the asset's life, with the expectation of paying higher rates in the future in order to pay the DTL. If the asset was subject to normalization tax accounting, the ratepayers have funded the DTL; thus, there will not generally be a regulatory asset in conjunction with normalized assets.

1.7 REGULATORY LIABILITY OR PAYABLE

Amounts owed by the utilities to ratepayers.

2 <u>The Ratemaking Tax Algorithm</u>

This complex issue of fixed asset taxation can be clarified through understanding the following principles:

2.1 Depreciation is beneficial to ratepayers and utilities because it is deductible, and therefore lowers tax expense.

2.2 Book and tax depreciation at the end of life for any given asset will be exactly the same.

2.3 If book and tax depreciation during the life of the asset is the same, taxes do not present an issue because there is conformity between the book and tax expense levels. The ratemaking revenue requirement would be based solely on recovery of the plant investment.

2.4 However, tax depreciation is generally accelerated compared to book depreciation, creating a "gap" between book and tax during the life of the asset.

2.5 As this gap is closed (via reimbursement in rates for book deprecation that is treated as income for tax purposes because accelerated tax depreciation has already reduced taxable income in prior periods), taxes will be due to the taxing authorities.

2.6 If ratepayers reimbursed utilities for tax expense based on actual tax depreciation ("flow-through"), then ratepayers will benefit from lower rates as the gap builds up, but must pay higher rates to close the gap in the later years of the asset's life, because utilities will pay taxes on the gap.

2.7 If ratepayers reimbursed utilities for tax expense as if book depreciation were deductible, then they have funded ("normalized") the taxes due on the gap. Ratepayer funding will be used on behalf of ratepayers to pay taxes due to taxing authorities as the gap is closed.

3 Complications Raised by the CTC

3.1 As noted above, either the flow-through or normalized methods of tax accounting will generally yield the same revenue requirement over the life of the asset. (The normalization method will produce a somewhat lower revenue requirement in nominal dollars, since the Deferred Tax Reserve lowers rate base, and thus the return component of rates).

3.2 Under CTC, the regulated status of the assets will come to a close at the end of the transition period; this is generally before the assets will have fully depreciated. This book depreciation is now being accelerated; thus there is a need to fund taxes on the "gap" under CTC that would normally unwind in due course under cost-of-service regulation, but which will now be accelerated.

3.3 In effect, the Preferred Policy Decision and AB 1890 require utilities to credit ratepayers for the reversal of the Deferred Tax Reserve in computing the CTC revenue requirement. In addition, ratepayers must now make a "catch up" payment over the transition period to repay the benefits previously received by ratepayers on the flow-through assets and to fund the Deferred Tax Reserve. Once funded, the Deferred Tax Reserve will be used to pay taxes due to taxing authorities.

(END OF ATTACHMENT 5)

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(END OF APPENDIX A)

A. 96-08-001 et al.
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COMMISSIONER JESSIE J. KNIGHT, JR., CONCURRING:

The estimated eligible transition costs are large, but I am confident that they been reduced to the greatest practical extent under the law. More importantly, this reiterates the key policy principle that going forward costs must be recovered from the market. I concur with this policy principle. Once a generation plant has been given its market valuation, that plant must make economic sense to operate on a going-forward basis. The utility will have to make the business decision as to whether the plant should continue to operate. It is imperative that utilities not have competitive advantage through transition cost subsidization of assets that are uneconomic on a going forward basis. If a plant cannot compete on a going-forward basis it has no place in a competitive market and no place in California's future.

I take this opportunity to express my commitment that the Commission will thoroughly review amounts posted to the transition cost balancing account in this proceeding, and particularly the monthly posting to the plant-specific accounts, to ensure that transition costs are minimized and to prevent any competitive advantage to utility plants that could arise by transition cost subsidization of plant operating costs.

This decision estimates the total costs eligible for transition costs recovery. We know that the actual amount of transition costs will be less than this because this estimation will be offset by the market valuation of the plants and other assets. What we can say with certainty is that these are not new costs and that these costs would have been recovered from ratepayers under the traditional regulatory framework. In fact, absent restructuring these costs would have been higher because they would have been subjected to the higher carrying costs reflected by the utilities cost of capital. Furthermore, we can only begin to ponder what the next generation of uneconomic investments would have looked like had the discipline of competitive marketplaces not been introduced to the electricity industry and those who regulate it.

It is not competition that resulted in these costs. Rather, it is competition that brought light to the fact that the traditional cost-of-service regulatory model had resulted in uneconomic investments. The exact magnitude of these uneconomic investments is not known, but today we have estimated what the upper limits are.

This decision tackles very tough issues. It seeks to implement the various provision of state law that govern the recovery of uneconomic costs of the utilities. AB 1890 did not leave this Commission with much policy discretion with respect to so called transition costs. This decision applies the law to the facts.

Dated November 19, 1997 in San Francisco, California.

/s/ Jessie J. Knight, Jr.
Jessie J. Knight, Jr.
Commissioner