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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of PACIFIC POWER & LIGHT COMPANY Under Section 454 of the Public Utilities Code of the State of California for Authority to Increase Rates for Service.	Application 83-05-52 (Filed May 25, 1983)
And Related Matter.	Application 83-07-17 (Filed July 8, 1983)

(See Appendix A for appearances.)

TABLE OF CONTENTS OF OPINION AND ORDER

OPINION

I. SUMMARY OF THIS DECISION

This decision authorizes Pacific Power and Light Company (PP&L) to increase its rates for electricity in its northern California service areas by $6.7 million for the test year 1984, which is approximately a 15.25% increase over existing rates. PP&L requested an aggregate increase of $10.8 million in two separate applications, which were heard and decided on a consolidated record.

The decision provides PP&L with a 15.50% base return on equity. This translates to an authorized rate of return of 12.02%. PP&L had requested a 16% base return on common equity plus a minimum of 2.0% risk allowance for the effects of the nuclear abandonments. This decision leaves open the determination of an allowance for the risk effects of our denial of recovery of PP&L's allocated share of the cost of the two abandoned nuclear generating projects. Decision 84-05-097, which denied recovery, is on appeal and we do not want to prejudge the outcome of that case. Further, a second Application for Rehearing is pending before us. We will want to consider all implications before assigning or not assigning a risk factor.

Because of the difficulty in estimating total electric sales for the test year, we have followed the pattern we have adopted for other California electric utilities. This decision establishes for PP&L an electric revenue adjustment mechanism (ERAM) which will adjust electric rates for changes in operating revenues from unexpected fluctuations in sales. To the extent that sales of electricity are higher or lower than forecasted, for the future PP&L or its ratepayers will be made whole.

PP&L is authorized to file for an attrition allowance in 1985 which will reflect the most recent estimates of changes in the level of operating expenses resulting from inflation.

The decision puts into effect for PP&L standard baseline (lifeline) allowances as required by the Sher Bill which was enacted by the legislature in 1982. The baseline rate becomes the first tier of the two-tier residential rate structure.

II. INTRODUCTION

A. Procedural Background

On May 25, 1983, PP&L filed A.83-05-52, which requests Commission authorization of a general increase in electric rates of $6,034,000 based upon the utility's estimate of test year 1984 results of operations. On July 8, 1983, PP&L filed A.83-07-17, which requests authorization of a further rate increase to yield an additional $4,913,000 in revenues based upon the utility's projection of changes in electricity consumption for the 12-month period ending July 31, 1984. A.83-07-17 also asks the Commission to authorize an ongoing ERAM to provide for future increases or decreases in PP&L's rates based upon the relationship of actual electricity sales to the corresponding test year revenues adopted in general rate cases.

At the prehearing conference held on July 29, 1983, the presiding Administrative Law Judge (ALJ) directed that A.83-05-52 and A.83-07-17 be heard on a consolidated record. According to PP&L the total rate increase which the utility is requesting amounts to $10,873,000 for the test year 1984 when the revenue effects of the two applications are combined on a consistent basis.

B. Public Hearings

In early October, two days of hearings for public witness testimony were held before ALJ Haley in Crescent City and two days in Yreka, with an evening session being held at each location. Altogether, about 400 PP&L ratepayers attended these hearings, and of that number over 50 persons made statements in opposition to the rate increase. Following the public witness hearings, 11 days of evidentiary hearings were held in San Francisco, concluding with oral argument on December 13, 1983 when the matter was taken under submission subject to the filing of briefs on January 6, 1984.

In addition to the utility and the staff (both of whom introduced complete results of operations studies and participated in the resolution of all issues) five other interested parties entered appearances and participated in portions of the public hearings: California Farm Bureau Federation (CFBF), Toward Utility Rate Normalization (TURN), Congressman Douglas H. Bosco,[1] and the Siskiyou Cattlemen's Association and Klamath Basin Haygrowers.

C. PP&L's Operations

PP&L is a large diversified corporation. Its widespread operations encompass three distinct business sectors: (1) electric generation, transmission and service; (2) telecommunications and related technologies; and (3) mining and resource development. Of the three , the electric utility sector is by far the largest. PP&L's electric operations serve over 650,000 customers, only about five percent of whom are located in California's three northern border counties of Del Norte, Siskiyou, and Modoc. The other 95 percent are situated in Idaho, Montana, Oregon, Washington, and Wyoming. As an electric utility, PP&L operates 33 hydro generating stations as well as four major steam plants. Its telephone subsidiary, Pacific Telecom, is the fifth largest non-Bell telecommunications company in the country, providing service in six northwestern states and Alaska. Its wholly owned subsidiary, NERCO, one of PP&L's resource development and exploitation activities, operates 10 coal mines in five states. PP&L's consolidated corporate revenues in 1982 were $1.4 billion, of which California jurisdictional sales of electricity accounted for less than $50 million.

[1] Congressman Bosco represents the First Congressional District in the United States House of Representatives. His participation in this proceeding is on behalf of his Del Norte County constituents.

D. The Issues

The issues presented in this proceeding are listed below in the order in which they are discussed in this decision.

1. Jurisdictional allocation.
2. Sales of electricity forecast.
3. Electric revenue adjustment mechanism.
4. Production expenses other than coal.
5. Cost of coal.
6. Bonneville Power Administration rate increase.
7. Safe harbor lease (Malin-Midpoint transmission line).
8. Treatment of capitalized benefits for tax purposes.
9. Repair allowance deduction.
10. Miscellaneous tax issues.
11. Plant held for future use.
12. Other deferred debits included in rate base.
13. Colstrip Unit No. 3.
14. Cost of equity capital.
15. Effects of abandoned nuclear projects on cost of equity capital.
16. Conservation programs.
17. Long-run incremental costs.
18. Cost allocation to customer classes.
19. Rate design within customer classes.
20. Comparative rates.
21. Notice to the public as to (a) the amount of the requested increase and (b) consideration of the effects of abandoned nuclear projects.

In addition, we raise the issue of the need for a general schedule for utilities not now covered by our Rate Case Plan. We recognize that, due to a series of delays on the part of both the company and our own staff, that we are today issuing a decision for test year 1984, now half over. We direct our Executive Director to review our processes with the goal of developing such a general schedule for the parties involved.

III. JURISDICTIONAL ALLOCATION

Because Pacific operates an integrated electric utility system serving a number of states, it is necessary to allocate joint plant and expenses among the respective jurisdictions for rate-fixing purposes.

The revenue requirement underlying PP&L's requested rates is based upon the coincidental-peak allocation method upon which the utility has previously relied in its California proceedings. This method has been adopted for rate-fixing allocation purposes by all of the jurisdictions in which PP&L provides electric service except California. The staff showing is based on the relative-use method which the Commission adopted as an interim approach in D.82-12-071 in A.60560, PP&L's last general rate case.

It is PP&L's position that if different allocation methods are adopted for rate-fixing purposes by the several states, the utility has no assurance that it will have a reasonable opportunity to recover its cost of providing electric service. In support of this portion, PP&L points out that Exhibit 59, the joint staff-utility overall comparison exhibit, shows the staff's revenue requirement figure for the test year 1984 to be $1.21 million lower than the utility's number solely because of this use of different jurisdictional allocation methods.

In D.82-05-42, the first interim decision in A.60560, we said:

> "The method for allocating costs and investments to California from Pacific's total system was a hotly contested issue as it was in Pacific's 1979 rate case. This interim decision does not adopt any portion of Pacific's requested rate increase that was subject to dispute by other parties on the basis of differing jurisdictional allocation methods. A final decision on allocation methods will be made

> after further hearings. Other states will be encouraged to participate in the hearings. We defer final judgment on the allocation method pending the conclusion of these hearings because we believe that it is undesirable to unilaterally change the jurisdictional allocation method without consultation with other states and without the development of a more comprehensive record on allocation procedures."

Subsequently, in D.82-12-071, our second interim decision in that rate case, we stated:

> "The four days of further hearings in this proceeding, which were held for the limited purpose of taking evidence on jurisdictional allocations, produced little in the way of new facts on which the Commission can base a decision. Other than a clarification of the staff's relative use method and an exposition of how selective-type LRIC studies might be used for allocating, the only significant information gathered was reinforcement of the opposition of the other states to any unilateral action on allocations by California. We will adopt the relative use method for this application and, pending final agreement among the states, for any future Pacific rate increase applications. We believe, at this time, it is the best method because it is a reasonable interim approach that will accomplish two things. It will give some recognition to the problem of disparity of growth among the states and, more importantly, give a strong signal of California's desire for a revised allocation procedure that will reflect that disparity of growth on a continuing and fair basis."

In D.82-12-071, we charged our staff with taking the lead in moving toward a consensus among the states in developing a revised allocation methodology which would be acceptable to each of the jurisdictions. According to staff testimony in this proceeding, the staff has on several occasions since the issuance of that decision participated in meetings and communicated by correspondence with the representatives of the other commissions concerned with the jurisdictional allocation. The staff witness testified that the various states had not reached a final agreement regarding method; however, at a meeting of state representatives held July 15, 1983, there was a general consensus that favored the methodology of the NARUC Electric Cost Allocation Manual published in 1973.

It is apparent that the "final agreement" we had hoped for will not be realized in the foreseeable future, if ever. In the meanwhile, we have grown increasingly concerned as to the appropriateness of the relative-use method we adopted as an interim measure in the last rate case. In that rate case, the difference in annual revenue requirements determined by the coincidental peak allocation method and the relative use method was only $585,000. This difference has grown to $1,210,000 in this proceeding, and the indications are that this difference will continue to grow. It would seem to ensue, therefore, that an ever increasing portion of PP&L's plant investment and operation costs will be relegated to a jurisdictional no-man's land with an undesirable impact on PP&L's credit and its cost of money. Our original purpose, which was to assure Californians would bear no unjustified rate burden, would not be met, and thus our allocation endeavors could be self defeating.

The staff witness testified that the only reason that the NARUC method was not reflected in the staff's presentation was that consensus reached at the July 15, 1983 meeting occurred too late for this proceeding. Although no party sponsored an allocation based on the NARUC methodology, the sketchy evidence of record shows that it would probably result in an allocation of about 3.94% to California compared to 3.88% for the coincidental peak method. Viewed in this light, PP&L's allocation method appears to produce a conservative and reasonable allocation to California. However, PP&L did not present sufficient evidence to cause us to abandon the relative-use method of allocation for purposes of determining the revenue requirement in this proceeding.

At this time, we are placing PP&L and our staff on notice that in the utility's next rate case, the showing of each should include, in addition to whatever methodology they may prefer, an allocation study based on the consensus methodology using the 1973 NARUC allocation manual as well as an allocation based upon the relative-use method.

IV. OPERATING REVENUES

A. Sales of Electricity

The staff differs with PP&L's electricity sales forecast with respect to industrial sales and special sales for resale. The staff estimates test year 1984 industrial sales at 65,500 megawatthours (MWh), or at a level 11.3% higher than PP&L's figure of 57,905 MWh. This difference in sales forecasts equates to a revenue requirement difference of $498,000 for the test year.

At the hearings, the PP&L load witness testified that nine months of actual experience subsequent to the date on which the sales estimate was made shows the utility's forecast for California sales to be within one percent of actual experience, with the actual loads experienced being below those forecast. This witness testified further that his best current estimate of loads would result in the utility sponsoring a lower sales forecast if afforded the opportunity.

The staff's higher estimate of 1984 industrial sales results in part from its prediction of a greater economic recovery, particularly in the region's logging and wood products industries, and in part from the staff's use of a different forecasting method.[2]

The record shows that PP&L's actual experience has been that sales to industrial customers during the first nine months of 1983, exceeded its forecasted sales by 39%. PP&L's rationale for this development is that the higher sales were not a result of an upsurge in the economy of the area but, instead, resulted from the reopening of one paper mill and a higher-than-forecasted level activity at a new gold mine.

We are of the opinion that the present and near-term trends in the economy of California give greater support to the staff forecast of industrial sales than to that of PP&L. These encouraging economic trends, plus the fact that the staff's forecast is based on later load data than the utility's forecast, convince us that we should adopt the staff estimate of electricity sales for the test year 1984.

We note PP&L's objection to the fact that the cost effect of the staff increase in the sales forecast was not carried through to other portions of the staff case. PP&L is correct in its assertion that the staff has made no parallel adjustment to recognize

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2 The staff position on economic trends through 1984 was based in part on the June 1983 forecasts from Data Resources, Incorporated (DRI) and the Summer 1983 UCLA Business Forecasting Project. PP&L's forecasts were prepared in October 1982 and were not subsequently changed. The staff forecast of industrial sales was made using a different methodology than PP&L employed. The staff used a macroeconomic equation for the period 1970-1983 by quarters to develop its estimates. PP&L relied mainly on cross-sectional econometric equations to model changes in the industrial sector.

either (1) the lower wholesale sales which would result from the increase in retail sales or (2) the increased production costs to produce the increase in retail sales. It is obvious that PP&L cannot generate an extra 8,000,000 kWh without incurring related costs. Accordingly, we will adjust the appropriate elements of our adopted test year results of operation to reflect these additional costs.

B. Electric Revenue Adjustment Mechanism

On July 8, 1983, or about six weeks after filing its application for a $6,024,000 general rate increase, PP&L filed its second rate increase application requesting (1) an additional increase of $4,913,000 and (2) the establishment of an ERAM provision in its tariffs. In reponse to the Commission's consolidation of the two applications, PP&L filed supplemental exhibits (Exhibits 19, 20, 21, 22, and 23) on August 18, 1983, reflecting the combined revenue requirement increase as $10,873,000.

We have over the past several years established ERAMs for all of the major California electric utilities, including Pacific Gas and Electric, San Diego Gas and Electric, Southern California Edison, and Sierra Pacific Power. The purpose of the ERAMs that we have placed in effect throughout the electric utility industry in California is to reflect in rates over- and undercollections of adopted operating revenues caused by fluctuations in sales. Through the application of such a mechanism, the utility is afforded a better opportunity to earn its authorized rate of return during the test year and the attrition year by our allowing it to collect the intended amount of adopted operating revenues. The ratepayer is, in turn, afforded protection, because the mechanism ensures that the utility retains no more than that amount of revenues. Furthermore, the adoption of a revenue adjustment mechanism is effective in eliminating disincentives for the utility to promote the conservation policies enunciated by this Commission.

It is unrealistic to expect that all of the key assumptions reflected in a revenue forecast will be borne out during the two-year period for which rates are being set. Unforeseen and unpredictable factors, which are beyond control by the utility, usually cause recorded revenues to be greater or smaller than the adopted test-period level of operating revenues. Departures from the forecast assumptions become more critical as the magnitude of the authorized revenue increases.

Among revenue forecasting considerations that have a high degree of uncertainty for an electric utility are the following key factors:

a. The effect on electricity sales of a high level of increase in rates.

b. The response of customers to the utility's conservation and load management programs in reducing their energy consumption.

c. The potential for revenue instability resulting from customer reaction to changes in rate design.

d. The uncertainty of fuel prices and their effects on overall rates and sales.

e. The impact of weather on electricity sales.

f. The uncertainty of the economy, including the impacts of inflation and unemployment on electricity sales.

g. The gain or loss of large commercial and industrial customers with attendant shifts and changes in electricity sales.

Subject to certain modifications, the staff supports PP&L's request for the adoption of an ERAM . In addition to technical changes in language, the staff recommends the establishment of: (1) a "cap" on ERAM so that PP&L does not exceed its authorized rate of return; and (2) a range of revenue fluctuation of one to two percent around which the mechanism would not be triggered.

PP&L disagrees with the second of the staff's suggested modifications to the ERAM proposal. PP&L contends that it is difficult to tell how the staff would compute this range. PP&L brings out that the staff witness testified at one point that a $2.1 million undercollection in 1982 would represent only a negative 0.93% undercollection and, at another point that an $0.5 million undercollection at a higher revenue was equivalent to a one percent undercollection. PP&L emphasizes that the staff has sponsored a sales forecast approximately one percent greater than the utility, with this difference representing approximately $500,000 in revenues. PP&L reasons that, if the staff ERAM range proposal were adopted and if actual sales prove to be equal to the utility's forecast, a substantial revenue loss would occur which could not be corrected through the ERAM . PP&L argues that such an undercollection would be much more likely than any overcollection because, it asserts, even its lower forecast of California sales is turning out to be greater than actual sales. PP&L's position is that its customers would be adequately protected by the establishment of a cap preventing returns over those authorized and that, therefore, the staff's additional proposal of a triggering range should be rejected.

Congressman Bosco's representative, as well as a number of the participating members of the public, oppose the establishment of an ERAM mechanism. They contend that it would result in too-frequent rate increases, that it would detract from the conservation effort, and that it would shift the stockholders' risk to the ratepayer. These issues are not unique to PP&L's situation; they are generic to the ERAM concept. We are of the opinion that any such effects on PP&L would, as they are for the rest of the California electric utility industry, be more than offset by the advantages that accrue to the ratepayer and stockholder alike.

Accordingly, we will deny Congressman Bosco's motion to dismiss PP&L's ERAM application. We will adopt PP&L's proposal in part as shown in Appendix B prospectively except that we will provide for interest to accrue at the 3-month commercial paper rate as we do for other utility ERAM balancing accounts. To the extent that PP&L requests adjustment in ERAM to recover lost sales revenues resulting from actual sales differing from forecast sales adopted in PP&L's last general rate case, the application is denied. We will not adopt the staff's recommendation for a range of revenues as a triggering device for the ERAM or for the establishment of a cap as this would be a departure from established ERAM procedure. We may, however, wish to examine the concept of a cap on ERAMs in some future generic proceeding.

V. OPERATING EXPENSES

A. Production Expenses Excluding Coal

There is a difference of $348,000, after allocation to California, between the PP&L and staff estimates of 1984 production expenses at the utility's coal plants, excluding the cost of coal. PP&L and the staff agree on the escalation rate to be used to forecast 1984 budgets, but they do not agree on the 1983 base figure to be escalated. PP&L used its actual 1983 steam plant budget as a base figure. The staff, on the other hand, derived its 1983 base by escalating 1982 actual expenses by the percentage change between PP&L's 1982 and 1983 budgets.

The staff brings out certain problems associated with PP&L's proposal to use the 1983 plant budgets as the base amount. One problem is that the 1983 budgets were created in 1982 before many of PP&L's recent cost control measures were adopted; therefore, the 1983 budgets are a less accurate indicator of actual 1983 expenses than the utility's 1982 recorded expenses. Another problem is that the 1983 budgets appear to have included $9.7 million for maintenance expenses scheduled to be accomplished in 1982 but deferred to 1983. The staff contends that the utility has adopted a a continuing deferred-maintenance policy which will jeopardize the public interest and increase production expenses. In support of this position, the staff in its brief cites the following testimony of a PP&L witness at transcript (TR) 740:

> "Now, we planned [in May 1983] to shift a sizeable amount of maintenance, once again, forward into 1984.
>
> "But, like in a lot of cases, the plans just aren't working very well because by deferring the maintenance of Unit No. 1 at Centralia, as an example, we ran too far.
>
> "We should really have taken that unit down for annual maintenance this summer.
>
> "And what has happened to us is that we have had some severe mechanical difficulties with that unit, wherein it is going to be off-line for approximately 30 days.
>
> "We are going to do a quick fix on it and get it back on so we can continue to make sales for resale to keep our customers' rates as low as possible.
>
> "If that doesn't work, it's possible that the unit could be down for the entire portion of the year that remains."

The staff takes the position that the base used for estimating 1984 expenses should not include one-time expenses incurred in 1983 that should have been made in 1982, especially expenses which would not have arisen had PP&L not deferred maintenance. The staff argues that the testimony shows that some of the maintenance scheduled for 1983 was deferred so that PP&L could keep its dividends high. The staff accuses PP&L of deliberately taking an unwarranted risk which resulted in the deterioration of electric plant in order that the utility would not have to reduce its dividend.

We agree with the staff position that the ratepayers should not be called upon to pay the additional costs associated with a decision which PP&L appears to have taken solely for the benefit of its stockholders. Accordingly, we will adopt the staff estimate for production expenses (excluding fuel) for coal-fired generating plant. This is the only portion of test-year production expenses (other than the cost of coal and the jurisdictional allocation) which remained at issue at the time of submission.

B. Cost of Coal

PP&L and the staff presented substantially different estimates of 1984 test year coal costs for the utility's Centralia, Dave Johnston and Wyodak steam-electric generating stations, the significant portion of the difference relating to the Centralia plant. The staff's estimate of coal costs would produce an allocated test year revenue requirement $324,000 lower than PP&L's. In addition, the staff estimate of coal cost would result in a rate base component due to the investment in coal inventory which is $65,000 lower than PP&L's estimate.

When PP&L prepared the showing it filed with the application, it determined the base price per ton by using actual coal costs recorded during the last four months of 1982 and then factoring the data upward using a December 1982 DRI escalation forecast. The staff used a similar approach to determine its base price. However, the staff used the average cost of coal during all of 1982 and escalated the data using a July 1983 DRI forecast.

We will adopt the utility's estimate for the cost of coal. During the hearings PP&L presented testimony showing the recorded 12-month average price for coal at Centralia as of August, 1983 to be $20.06 per ton. Escalating to a 1984 level of expense would result in a price for coal very close to PP&L's estimate of $21.30 per ton for 1984. We will also allow an additional $7,000 in test year fuel costs to reflect an allocation of higher fuel consumption related to the greater megawatt hour sales reflected in the revenue figure we are adopting.

C. Purchased Power Expenses

In early October, during the course of the hearings in these proceedings, PP&L learned of the Bonneville Power Administration (PBA) intention to increase the rates it charges PP&L for electric power effective November 1, 1983. PP&L shortly thereafter introduced Exhibit 20A containing Table 20A-11C which detailed the revenue requirement effect of the imminent BPA increase. The staff immediately moved to strike this table on the grounds that it was introduced without notice to interested parties and in an untimely manner without a showing of good cause. The presiding ALJ denied the motion, and at this time that portion of the staff's petition of November 14, 1983 relating to BPA is still pending.[3] In his opening brief, staff counsel continues to maintain his position in opposition to the inclusion of the BPA increase in the determination of PP&L's test year 1984 revenue requirement.

Table 20A-11C of Exhibit 20A shows the impact of BPA's proposed increase on 1984 test year results of operations for California to be $719,000. This figure was reviewed and accepted by the staff. Subsequent to the PP&L and staff presentations on this issue, the Federal Energy Regulatory Commission (FERC) suspended the portion of the BPA increase relating to wheeling expenses. In recognition of this suspension, PP&L and the staff removed the transmission portion of the BPA increase from Exhibit 53, the joint utility staff exhibit which compares their respective estimated

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[3] The staff's November 14, 1983 petition requesting the Commission to overrule the ALJ is discussed in greater detail under the side-heading "Colstrip Unit Number 3", infra.

results of operations for test year 1984. The impact of the suspension was to reduce the revenue requirement for California by $236,000. Staff counsel, in his opening brief, contends that, if PP&L's BPA-related request is considered at all, it should include only the reduced increase of $483,000 that came into effect on November 1, 1983.

We have considered staff counsel's pending motion to strike Table 20A-11C of Exhibit 20A. We find no merit in his position that it should be stricken on the bases it was untimely and notice was not given to interested parties. We will confirm the ALJ's ruling denying the motion to strike Table 20A-11C. We are in agreement with the assigned Commissioner, who in his ruling of December 9, infra, commented as follows on this aspect of staff counsel's motion:

> "In a recently filed joint company and staff exhibit, No. 53, both parties agree that $483,000 is the increased revenue requirement due to the BPA rate increase. Since this increase is imposed by another governmental entity and PP&L must implement it, I see no reason to delay that implementation. I agree with ALJ Haley that Table 20A-11C of Exhibit 20A should not be stricken from the record of this proceeding."

In the meantime, the issue as to whether the annual effect of the BPA increase on PP&L's operating expenses for California will be $719,000 or $483,000 has been resolved by an action of the FERC. We take official notice of the FERC's "Order Granting Request for Temporary Interim Rates, Denying Renewal Motion for Partial Summary Disposition, Granting Request for Clarification and Referring Action on Requests for Hearing", issued January 27, 1984, in Docket

Nos. EF84-2011-002, et al. In taking this action, the FERC has approved the BPA transmission increase effective February 1, 1984, which has the effect of establishing the total impact on California operations at the $719,000 figure. Accordingly, we will include the higher amount in our adopted results for the 1984 test period.

In addition to the difference between staff and PP&L relating to the BPA rate increase, there is a difference of about $60,000 in estimated purchased power costs, with the staff estimate being higher. This difference, which arises from the staff's lower estimate for the coal price at Centralia mine, would produce a lower sales price for PP&L and result in a lower offset that would ultimately increase PP&L's purchased power costs. However, because we have adopted PP&L's cost of coal at Centralia, this $60,000 difference is eliminated. Therefore, we will exclude this amount of expense in determining the adopted test year revenue requirement.

D. Safe Harbor Lease

Section 201a of the Economic Recovery Tax Act (ERTA) permits the owner of certain qualifying property to sell the associated federal income tax benefits to a third party. Pursuant to this provision of ERTA, PP&L entered into a so-called "safe harbor lease" agreement under the terms of which it sold all of the investment tax credits and all of the income tax depreciation related to its Malin-Midpoint 500-kilovolt transmission line to a subsidiary of Standard Oil Company of Indiana, Amoco Tax Leasing XVIII Corporation (Amoco). According to the staff's Exhibit 38, the agreement provides as follows:

> "1. The total construction cost of the plant to PP&L was $181,023,000, including $34,758,000 of overheads which PP&L had previously deducted for tax purposes leaving a tax basis cost of $146,265,000. The selling price to Amoco was the tax basis cost of $146,265,000 derived above.
>
> "2. Amoco made a downpayment of $43,869,094 and will pay the balance of $102,395,966 to PP&L over 30 years at an annual interest rate of 17%.
>
> "3. PP&L's lease payments to Amoco are exactly equal to Amoco's loan payment to PP&L. In effect, after the payment of $43,869,094 there are no further cash transactions between PP&L and Amoco."

The staff views the effect of this transaction simply as a reduction of PP&L's $181 million investment in the transmission line by $44 million, leaving an actual investment of $137 million in the transmission line. It is the staff's position that only this $137 million remainder should be included in rate base. Further, the staff arrives at a net plant investment, on a tax basis, of $102 million ($137 million less the $35 million previously deducted) and imputes normalized tax depreciation for ratemaking using this $102 million tax basis.

PP&L presents its case as if it had continued to retain the related tax benefits. PP&L points out that this position is consistent with both its and the staff's treatment of the safe harbor lease which the Commission adopted in D.83-03-059 in the utility's last general rate case. PP&L contends that the staff, in departing from the previously adopted treatment, is taking two mutually inconsistent positions: (1) the staff recognizes that the tax benefits were sold by reducing rate base by the $43 million cash payment received from Amoco; and (2) it then reverses its position and imputes some of the tax benefits that were sold to further reduce the utility's revenue requirement.

We agree with PP&L's assertion that this treatment "double counts". Staff's position is self-contradictory; its parts are mutually opposed. The staff cannot both reduce rate base by the proceeds from the sale of the tax benefits and then continue to apply the tax benefits to further reduce the revenue requirement. For adopted test year purposes, we will reduce PP&L's rate base by the $44 million payment received by Amoco; however, we will determine income taxes for rate fixing purposes without imputing any tax benefits associated with the investment tax credits and income tax depreciation which were sold to Amoco in consideration of the $44 million payment. In this manner, the ratepaying public will receive the full benefit of the proceeds of the safe harbor lease.

E. Treatment of Capitalized Benefits and Taxes for Tax Purposes

The staff reduces its estimate of test year 1984 tax expenses by deducting certain employee benefits and taxes other than income which PP&L elects to charge to construction and capitalize rather than take the option provided by law of expensing those costs. The staff assumes that PP&L has expensed these items for tax purposes. In its brief, the staff stipulates to the utility's treatment of life insurance expenses, thus removing employee benefits from this issue.

As to the capitalized taxes part of this issue, it appears that the staff adjustment double counts. The staff accepted PP&L's tax basis adjustment calculation; however, the utility has capitalized these certain taxes since 1981. By not adjusting this calculation, the staff takes both a current deduction and a deduction through tax depreciation. We must reject a calculation in which the same costs are both capitalized and expensed. Accordingly, we will adopt the utility's position on this issue.

F. Repair Allowance Deduction for Income Tax Purposes

Under California law, PP&L has the option of deducting an estimated repair allowance in computing state income taxes (CCFT). The utility has opted instead to deduct the actual repair costs it has experienced. The staff, on the other hand, has assumed that the utility has elected to use the repair allowance deduction and, in determining revenue requirement, has imputed to PP&L the tax savings resulting from such an election. The staff treatment of repair allowance has the effect of reducing test year 1984 CCFT by $358,000. This is offset, in part, by the effect of the staff treatment on federal income taxes which are thereby increased by $165,000.

We reason that the staff treatment is correct because it follows the precept that income tax determinations for rate-fixing purposes should use those lawful options which will minimize revenue requirement. We will, therefore, adopt the staff approach in our calculation of income taxes for the adopted test year results.

The staff's treatment is consistent with past Commission decisions on this subject. Both of the recent decisions involving general rate increases for PG&E (D.83-12-068) and for SDG&E (D.83-12-065) incorporate the repair allowance deduction for CCFT. However, PP&L has pointed out in testimony and in its brief that staff's calculation of the repair allowance is not correct. When corrected the repair allowance deduction for CCFT is corrected by reducing it to $796,000, there is a corresponding reduction in CCFT depreciation of $58,000. The result is a $71,000 decrease in CCFT and a $33,000 increase in FIT for a net decrease in income taxes of $38,000. We believe PP&L's numbers are reasonable, and we will adopt them for test period purposes.

G. Miscellaneous Tax Differences

There are three miscellaneous tax issues, the combined effect of which is a difference between PP&L and the staff in revenue requirement of only $5,000 for the test year. However, each of the three differences is fairly large standing alone, and the nature of each issue is sufficiently important to require that it be afforded separate discussion and resolution. The three tax issues relate to (1) coal mine and automobile depreciation and amortization deductions; (2) state deferred taxes; and (3) normalization of 1981 investment tax credits (ITC).

Regarding the first issue, PP&L deducts amortization expense for tax purposes, thus lowering its test year tax expenses. The staff does not do this. With respect to coal mine and automobile depreciation, the staff included these items in its tax depreciation expense, as did PP&L; however, the staff did not take the necessary corollary action of reversing book depreciation for these items. The effect of the staff handling of this issue is to incorrectly reduce revenue requirement by $149,000 for the test year. We will adopt the utility's treatment in determining the adopted test year results.

With regard to the second of these miscellaneous tax issues, PP&L included deferred taxes for the difference between guideline and straight-line rates for post-1980 plant additions. The staff did not recognize state deferred taxes for ratefixing purposes, thus reducing the test year revenue requirement by $64,000. The staff position agrees with our stated policies on the issue; therefore, we will adopt the staff treatment on this issue.

As to the third of these miscellaneous tax issues, the staff witness testified that the tax benefits of 1981 and prior investment tax credits have been flowed through. However, in OII-24, we adopted normalization of ITC generated in 1981 and thereafter in order to preserve the requirements of ERTA. Pacific has recognized this normalization treatment by amortizing 1981 ITC over a 30-year period, whereas the staff has excluded from its showing the unamortized balance of 1981. The utility's treatment, which we are adopting for test year purposes, reduces revenue requirement by $218,000; however, it protects the tax benefits provided to Pacific by ERTA.

VI. RATE BASE

A. Plant Held for Future Use

PP&L's rate base estimate includes a relative use allocation amount of $187,000 for plant held for future use (PHFU). The staff has adjusted PHFU downward by $163,000 to exclude from rate base seven properties that will not be placed in service before 1994. These properties include the specific future sites of three generating plants, one substation and the rights-of-way for three transmission lines. The staff takes the position that the seven properties should not be included in PHFU for rate base purposes unless the utility has definite plans to develop them within the next 10 years.

PP&L's witness admitted on cross-examination that the company has no plans to develop any of these sites within the next ten years. The staff's position is simply that property should not be considered as plant held for future use in rate base unless the company has specific plans to develop the property within the next decade. PP&L's position is apparently that any property owned by the utility which may ever become useful should be included in rate base. In our opinion the staff recommendation is reasonable and is consistent with recent Commission policy. Accordingly, we will adopt the staff exclusion of PHFU.

B. Other Deferred Debits
Included in Rate Base

PP&L has included in rate base $575,000 representing the allocated costs of certain items which the utility asserts are now providing service or are part of past costs incurred to provide service. These items include computer system expenses and the cost of overburden removal at Centralia coal mine. The staff has removed $549,000, or practically all of these costs, from rate base. The staff has, however, included $38,000 in amortization expenses to reflect the amortization over a four-year period of California's allocated portion of $3.5 million in computer system costs.

On a system basis, PP&L has incurred $11.3 million in costs associated with removing overburden (topsoil, rocks and vegetation overlying the coal seams) at its Centralia mine. These costs are expensed over the period during which the coal is burned. It is the staff position that these unamortized costs should not be included in rate base. PP&L has capitalized these expenses in order to recover its carrying costs.

We will adopt the company treatment of the computer system expenses. We have, however, re-examined the overburden issue, and it is our opinion that the ratepayers are the ultimate and obvious beneficiaries of the orderly and economic removal of the overburden at Centrailia mine. Equity requires that we recognize the large investment PP&L has made in preparing its coal mine to be advantageously exploited in order to provide coal to the ratepayer economically. Accordingly, we will allow the allocated costs of the removal of Centralia overburden to be included in test year 1984 rate base.

C. Colstrip Unit Number 3

Exhibit 20A was introduced by PP&L on October 19, 1983. Table 20A-11C of that exhibit presents test year 1984 effects of a November 1, 1983 rate increase by the BPA, and Table 20A-11D shows the effects of the inclusion of Colstrip Generating Station Unit 3 and related transmission plant (Colstrip 3) in rate base. Staff counsel made an oral motion to strike Tables 20A-11C and 20A-11D together with related oral testimony and to limit the further hearing set for December 12, 1983 to issues other than consideration of the Colstrip 3 in this rate case. The presiding ALJ denied staff's motion, and on November 14, staff counsel filed a petition requesting that the Commission overrule the ALJ.[4]

[4] Previously, on October 20, 1983, staff counsel filed a petition urging the Commission to overturn a ruling of the presiding ALJ which denied staff counsel's motion to strike PP&L's Exhibit 9 and Exhibit 10. We have considered staff counsel's October 20 petition, which has not heretofore been ruled upon, and we conclude that it should be denied.

On December 9, 1983, the assigned Commissioner filed a ruling, which we hereby confirm. In partially granting staff's motion, the ruling removes Colstrip 3, but not the BPA increase, as an issue from this proceeding.

VII. RATE OF RETURN

Rate of Return

Next to jurisdictional allocation, the issue of rate of return is the element of the estimated 1984 results of operations involving the largest revenue requirement difference between the utility and staff showings, i.e., $871,000 on an allocated test year basis. Table 1 is a comparison of the cost of capital estimates of PP&L and the staff together with the figures we are adopting for purposes of determining authorized rate of return for the test year 1984.

As Table 1 shows, the two parties imputed the same capital structure in their determination of rate of return, i.e., 52% long-term debt, 12% preferred stock and 36% common equity. In our opinion this capital structure is reasonable for this utility, and we will adopt it for purposes of 1984 test year results.

TABLE 1

Pacific Power & Light Company
Cost of Capital
Test Year 1984

Component	Capital Ratio	Cost	Weighted Cost
PP&L			
Long-Term Debt	52.00%	10.25%	5.33%
Preferred Stock	12.00	10.99	1.32
Common Equity	36.00	16.00	5.76
Total	100.00%		12.41%
Staff			
Long-Term Debt	52.00%	9.86%	5.13%
Preferred Stock	12.00	10.92	1.31
Common Equity	36.00	15.00-15.50	5.40-5.58
Total	100.00%		11.84-12.02%
Adopted			
Long-Term Debt	52.00%	9.86%	5.13%
Preferred Stock	12.00	10.92	1.31
Common Equity	36.00	15.50	5.58
Total	100.00%		12.02%

In its brief, the utility has in effect stipulated to the staff estimates for the cost of long-term debt and preferred stock. We have considered these stipulated cost-of-money estimates, and we regard them as reasonable and suitable for purposes of adopted test year 1984 results of operations. Therefore, the only cost-of-capital issue remaining to be resolved in this decision is what cost of common equity should be adopted for test year purposes.

A. Cost of Common Equity Capital

In support of its estimate of the cost of common equity, the utility's witness reviewed pertinent financial figures for PP&L and offered evidence (Exhibits 3 and 4) related to comparably situated utilities. In his analysis of cost of common equity PP&L's witness developed a range of 14.5% to 18%. His analysis of comparable companies produced a range of 15.43% to 17.24% with an average value of 16.22%. Based on this data, he estimated that PP&L's over-all cost of common equity is 17.25%. He concluded, however, that 16% would be appropriate for PP&L's California operations. He testified that he selected the lower end of the range on the basis of his assumptions that the proposed rates would become effective January 1, 1984,[5] that a reasonable attrition allowance would be allowed effective January 1, 1985, and that the proposed adjustment mechanisims would be implemented to deal with changes in forecasted conditions. The

5 PP&L's assumption of a January 1, 1984 effective date for the rate increase is hardly realistic, considering that the first of the consolidated applications in this proceeding was not filed until May 25, 1983 and the second not until July 8, 1983. Considering also that this rate proceeding was not taken under final submission until January 6, 1984, the assumption becomes an impossibility.

utility further states that, although it could justify a higher cost of common equity, it used the 16.00% adopted in PP&L's last general rate case, "in order to avoid controversy."

The staff estimates the cost of common equity to be in the range of 15.00% to 15.5%, and it recommends that 15.25% be used by the Commission in determining the allowed rate of return (before consideration of the effects of D.83-11-012). In determining this cost of common equity, the staff used several methods, i.e., discounted cash flow (DCF), risk premium analysis and an analysis of the earnings of comparable companies. The utility takes exception to the staff recommendation on the grounds that it fails to take into account the differences between PP&L and the comparable companies selected. PP&L argues that, because approximately half of its revenues come from telephone and coal operations, an investor would give equal weight to electric and nonelectric operations. PP&L contends that the staff should have separated out the telephone and coal operations in determining cost of capital by the DCF method and, further, that the nonelectric operations substantially affect the risk premium approach.

We note that since May 1982, when we issued D.82-05-042 allowing PP&L a 16.0% return on equity, the prime rate has declined from 16.5% to 12% and that yields on both long-term government bonds and AA utility bonds have declined as much as 200 basis points. We further note that D.82-05-042 did not provide an ERAM adjustment for PP&L. In this decision we are authorizing PP&L to establish an ERAM clause. This should significantly reduce, over the test year, the risk associated with the volatile sales characteristics of PP&L's

California electric operations. In consideration of these factors and other evidence on this record, we believe that a return on common equity of 15.5% is fair and reasonable.

B. Abandoned Nuclear Generating Projects

On November 15, 1983, the ALJ issued a written ruling taking official notice of D.83-11-012, which the Commission issued on November 2, 1983 in A.82-07-82. In that application PP&L requested authority to increase its California rates to recover its investment in two abandoned nuclear generating projects. The two projects are the Pebble Springs Nuclear Project, in which PP&L held a 29.4% interest, and the Washington Public Power Supply System Nuclear Plant No. 5, in which PP&L held a 10% interest.

D.83-11-012 ordered as follows:

"1. PP&L's request to amortize the costs of the abandoned Pebble Springs and WNP-5 projects is denied.

"2. The issue of risk to shareholders associated with the denial of amortization of abandonment losses shall be considered in determining the reasonable rate of return in PP&L's general rate case proceeding.

"3. The ratemaking treatment to be accorded the gain resulting from the debt/equity exchange shall be considered in PP&L's next general rate case proceeding."

The ALJ's ruling enlarged the scope of the hearing scheduled for December 12, 1983 in this proceeding to include the pertinent issues arising from D.83-11-012. At the December 12 hearing, parties so desiring were afforded the opportunity to present prepared testimony and/or exhibits as well as to conduct cross-examination relating to these additional issues.

On November 30, 1983, PP&L filed an application for rehearing of D.83-11-012. On May 16, 1984, we issued D.84-05-097 in the matter of the application for rehearing. D.84-05-097 made substantial modifications to D.83-11-012. PP&L has filed an application for Rehearing of D.84-05-097 as well as a Petition for Writ of Review (S.F. 24741) with the California Supreme Court. Because these proceedings are pending we will not decide the issues which arose in D.83-11-02 at this time but will hold them open for further review when the basic abandonment question is settled.

On June 1, 1984, the Commission staff petitioned the Commission to set aside and reopen this proceeding because of the issuance of D.84-05-102. We regard the action of reopening the proceeding as unnecessary, and we will deny staff's petition.

VIII. CONSERVATION PROGRAMS

PP&L regards itself as a leader in the conservation area, in which it has been active for over six years. The utility believes, and the staff agrees, that it would not be beneficial to its ratepayers either to terminate all of its conservation programs or to drop any particular program. PP&L and the staff concur, however, that conservation programs should be subject to continuing evaluation as to which are most cost effective. They also agree that, with the modifications proposed in this rate case, the existing programs should be continued through 1985. They believe that, given the staff's proposal for flexibility in funding the present programs, PP&L will be afforded the opportunity to promote the most cost effective programs even before any major revisions that may become effective after 1985.

During the next two years our staff will make reviews and recommend which programs should be terminated or continued beyond that date, as well as which programs should be added. In this proceeding, the staff has recommended modifying several programs and adding new programs which are currently authorized for other

California utilities. These programs include instituting a direct weatherization program for low income customers earning less than 150% of the poverty level, offering 150 rebates per year for purchasing energy-efficient refigerators, promoting the "one warm room" by subsidizing 100 electric portable space heaters for low income customers, and placing more emphasis on the rebate program and less on the loan program.

The cost effectiveness of PP&L's conservation programs is an issue which was raised in the hearings at Crescent City and Yreka by a number of participants and, in particular by Congressman Bosco's representative. According to the staff's Exhibit 41, the present average cost of electricity to PP&L's California ratepayers (at the tail-block rate) is about 5.6 cents per kWh and the marginal cost is 2.06 cents per kWh. At these levels many of PP&L's conservation programs would fail the Commission nonparticipants' cost-effectiveness test. This low marginal cost results primarily from a much greater than usual present supply of hydro-electric energy and capacity and a consequently lower than usual demand for PP&L's coal-fired resources. The staff witness emphasized, however, that a change in the supply picture is not unlikely, and this would cause the programs to become cost-effective again.

On November 2, 1983, the Commission issued Decision 83-11-047, which established a methodology for projecting short-run avoided costs in PP&L's service territory over the next 15 years. Neither staff's nor PP&L's cost-effectiveness analysis in this proceeding utilized the methodology adopted in the November decision. We expect, pursuant to D.83-11-047, that an updated filing of short-run avoided costs will be presented in PP&L's next general rate case. Staff and PP&L are directed to utilize the recently submitted projection in their ongoing cost-effectiveness evaluation of conservation programs. This will facilitate consistency across proceedings in evaluating PP&L's proposed resource additions and conservation programs.

In addition, we see no reason why the long run incremental cost used to allocate revenue requirements should not also be utilized in evaluating the cost-effectiveness of conservation programs that produce long-run energy savings. Parties are directed to present both sets of cost-effectiveness analysis in PP&L's next general rate case--one based on the short-run avoided cost methodology adopted in Decision 83-11-047 and one based on the long-run incremental cost methodology adopted for allocation purposes in this proceeding.

The total conservation budget recommended by the staff is $699,000 as compared to PP&L's initial request of $644,000. The main reasons for the staff recommending a higher figure are so that PP&L can: (1) create a direct weatherization program, (2) offer rebates to encourage customers to purchase energy efficient refigerators, and (3) participate in the "one warm room" program. The staff also believes that all monies allocated to home energy audits (HEA) not resulting in customer participation in one of PP&L's incentive programs should be charged to the HEA programs. The staff recommends that in the future all HEAs be accounted for separately and that the utility should note those HEAs which resulted in customers participating in other conservation programs.

The staff recommends that PP&L be required to furnish this Commission with brief quarterly reports illustrating the utility's expenses, accomplishments and expected annual energy saving attributed to each conservation program. It also recommends that PP&L continue its monitoring of energy savings using meter read data and be permitted management discretion to transfer up to $200,000 to more effective programs after consultation with the staff. Such a reallocation of funds may be necessary if the direct weatherization program, the rebate program, the efficient refigerator rebate program or the "one warm room" program have more demand than expected.

In the most recent Pacific Gas & Electric (PG&E) and San Diego Gas and Electric (SDG&E) general rate case decisions, we articulated our policies with regard to program cost-effectiveness and the overall level of funding for conservation and load management programs. This policy was stated in Decision 83-12-055 as follows:

> "We are persuaded that present circumstances require us to make a close examination of SDG&E's conservation programs. Several facts - that SDG&E's marginal costs are currently well below its average rate, that SDG&E is unlikely to face a capacity shortage in the next two years, that SDG&E's high rates already provide a substantial incentive for customer conservation - lead us to the conclusion that a less aggressive approach to conservation is now

> appropriate. At the same time, however, we are well aware that the energy situation may change dramatically and quickly. We are therefore reluctant to dismantle existing programs that may be highly beneficial in the future. The current circumstances thus present us with difficult choices. We reaffirm, however, that conservation is a preferred strategy for SDG&E; at the same time we recognize that the urgency of pursuing conservation may be less than in earlier years." (D.83-12-055, pp. 109-110).

Our funding guidelines for PP&L's conservation programs will reflect those adopted for San Diego Gas and Electric Company:

1. Maintain and implement those programs which are required by law or governmental mandate.

2. Continue those programs required by past Commission decisions but review them to determine if they should be continued.

3. Maintain and implement those programs which provide conservation services needed by customers.

4. Implement only those new programs which are clearly shown to be cost-effective and, in particular, will avoid the need for additional future system generation capacity.

5. Phase out present and reject proposed programs which require incentive payments to participants borne by all ratepayers including nonparticipants but which are only cost-effective to the participants.

6. Phase out present and reject proposed programs which, because of the potential for reduced billings, would probably be undertaken by participants without incentive payments.

7. Maintain or initiate programs which, although they may not meet some of the above objectives, are worthwile based on considerations of equity such as the ability of low-income groups to participate, externalities, and irreducible factors not subject to precise economic measurement.

We will expect PP&L and our staff to work closely during 1984 to effect the policy we have outlined above. Any problems with the program should be brought to our attention immediately through the advice letter filing procedure for our review and resolution.

Consistent with our "stay the course" policy adopted for SDG&E and PG&E, we will not adopt staff's recommendation to initiate a rebate program for energy efficient refrigerators and portable heaters for a "one warm room" program. In Decision 83-12-065, the Commission determined that these programs were not cost-effective. Further, the refrigerator rebate program is not particularly accessible to low income ratepayers. However, PP&L can produce written information on ways to reduce heating costs by the use of "one warm room", from its regular conservation education budget.

In order to enable greater participation of low-income families in the weatherization program, and reduce administrative costs, we will authorize the direct weatherization program recommended by staff. It is expected that PP&L will identify and weatherize at least 50 low income homes in its service territory, with costs at or below $800 per home. PP&L is directed to keep accurate records on costs and energy savings for review by this Commission in PP&L's next general rate case.

Our adopted expenses for PP&L's conservation programs for the test year will be $679,000. This amount specifically excludes any funding for the one warm room and the energy-efficient refrigerator programs. It reflects the change of the weatherization program from 0% to 8% financing. We will also authorize PP&L to transfer up to $100,000 for more effective programs following written notification of and agreement by the Executive Director. We also place PP&L on notice that we will give consideration to carrying over to the next general rate case the effects of any unspent conservation funds which were allowed for rate fixing purposes. We will direct the utility to submit the quarterly conservation reports recommended by the staff.

IX. ADOPTED RESULTS OF OPERATIONS

Although other parties participated in some aspects of the results of operations portion of this proceeding, only PP&L and the staff presented complete results of operations estimates upon which to determine the revenue requirement of the utility for the test year 1984. Table 2 shows the comparative estimates of PP&L and the staff at present rates, as finally presented in their joint late-filed Exhibit 53. Also shown for the test year in Table 2 are the adopted results of operations at authorized rates.

The adopted results reflect our determination of the individual issues as discussed in the preceding portions of this decision. The adopted results reflect the figures shown in Exhibit 53 with one exception, production expenses. Our adopted results, as we indicated in the earlier discussion, include the test year effects of the recent BPA rate increase at $719,000, rather than at $483,000 as reflected by PP&L and the staff in their comparative exhibit.

TABLE 2
Summary of Results of Operations
Comparison Test Year 1984
California Jurisdictional
(Thousands of Dollars)

	Present Rates			Authorized
	PP&L	Staff	Adopted	Rates
Operating Revenues				
Gen. Business Sales	$ 39,088	$ 39,590	$ 39,590	$ 46,327
Special Sales	4,449	4,159	4,159	4,159
Other Oper. Rev.	421	421	421	421
Total Oper. Rev.	43,958	44,170	44,170	50,907
Operating Expenses				
Production	15,581	14,407	14,682	14,682
Transmission	1,586	1,495	1,728	1,728
Distribution	2,344	2,344	2,344	2,344
Customer Accounts	978	978	978	978
Customer Serv.& Info.	589	589	569	569
Admin. & General	3,393	3,393	3,393	3,393
Subtotal	24,471	23,206	23,694	23,694
Depr. & Amort.	4,583	4,466	4,428	4,428
Taxes Other Than Income	2,065	2,016	2,016	2,099
State Income Tax	537	335	611	1,250
Net Fed. Inc. Tax	2,695	3,497	3,317	6,084
Deferred State Tax	40	-	-	-
Subtotal Tax	5,337	5,848	5,944	9,433
Total Oper. Exp.	34,391	33,520	34,066	37,555
Net Revenue	$ 9,567	$ 10,650	$ 10,104	$ 13,352
Rate Base	$114,976	$111,001	$111,085	$111,085
Rate of Return	8.32%	9.59%	9.10%	12.02%

X. ATTRITION

A joint exhibit was filed by the company and staff in which they agreed to use the Fall, 1984 DRI forecast for escalation of labor and non-labor expenses as a methodology for determining 1985 attrition. We adopt this methodology and those factors should be applied to the adopted 1984 expenses. We also adopt staff's recommendation that the 1984 expenses should first be shown in 1983 dollars and escalated for both 1984 and 1985. This would correct for any errors in 1984 escalation factors.

The company, in its brief, stipulated to all of staff's attrition calculations which include no financial attrition and $459,000 to cover additional capital costs. We will adopt staff's position.

PP&L is instructed to file an advice letter on or before October 15, 1984, setting forth the changed revenue requirement as a result of its changed expenses and capital costs. Any differences in revenues associated with increased or decreased sales in 1985 will be recovered through the ERAM procedure we establish today. We will also consider actual wage increases due to labor contracts negotiated prior to the filing of the advice letter.

Delays in Processing

We have acknowledged that this decision is issued with the 1984 test year now half over, this because of scheduling problems. To avoid similar problems in the future we direct our Executive Director to review our processes with the goal of developing a general schedule for utilities not now covered by our Rate Case Plan. The Executive Director should consider whether these utilities ought to be covered by the Rate Case Plan, or, if not, what steps are necessary to prevent delays in processing their general rate case applications.

XI. ELECTRIC RATES

A. Long-Run Incremental Costs (LRIC)

For the past several years, our policy in major electric utility rate cases has been to allocate revenue requirement to classes of customers based on formulae incorporating marginal costs. However, in D.92749[6] we recognized PP&L to be a special case among California electric utilities, and we encouraged the utility and our staff to develop an appropriate approach for PP&L.

The major factor which distinguishes PP&L from other California electric utilities is its generation resource mix, which includes a higher proportion of hydroelectric power. For purposes of a marginal cost study, the significance of this distinction is readily apparent. In the cases of the other electric utilities short-run marginal energy costs were based on the incremental costs of operating marginal oil-fired units. Thus, their short-run marginal energy costs are greater than their average energy costs because those utilities put their most-expensive-to-operate plants on line last. At any given time, therefore, there will be on line a combination of plants having an average operating cost lower than the marginal operating cost of the next unit.

PP&L, however, operates its system most efficiently by undertaking to run its base load coal plants at a constant level and meeting short-run changes in energy requirements by application of its available hydro resources. Since hydro power is generally cheaper than coal, PP&L's short-run marginal energy costs tend to be

6 Issued March 3, 1981, in OII 67, a statewide investigation regarding marginal cost methodology for electric utilities.

lower than its average energy cost. Thus, if we set rates on short-run marginal energy costs, PP&L's customers will receive a price signal that incremental energy costs are less than average costs, even though the utility's long-run incremental energy costs are much higher than its short-run or long-run average energy costs. Therefore, the use of short-run marginal energy cost is not appropriate for rate design purposes for PP&L, and we will again use LRIC for this purpose.

Both PP&L and the staff prepared LRIC studies which they followed to a greater or lesser extent in allocating revenue requirement among classes of customers. One significant difference between the two studies arises from the methods used by PP&L and the staff to develop real fixed charge rates which are applied to the marginal costs of capacity in Exhibit 14. PP&L uses a method which intially requires the selection of a "real discount rate" (a rate which is net of inflation). On the other hand, the staff uses a method which requires the selection of a "nominal discount rate" (one which includes inflation). Both methods are conceptually correct and will yield the same result if the initial discount rates are consistent with each other. This is where the difference between PP&L and the staff arises.

PP&L has selected a "real discount rate" of 4.5%. At the same time, PP&L uses 7% as an estimate of inflation. If the inflation rate is added to the real discount rate, the result is 11.5%, somewhat below PP&L's current cost of capital. Our perception is that PP&L's real discount rate is on the low side.

The staff's nominal discount rate is 15%. This is based on PP&L's nominal cost of capital. If the 7% inflation rate is subtracted, the result is a "real discount rate" of 8%. This is contrasted with the 4.5% rate which PP&L selected for use in its method of calculating the real fixed charge rates. For PP&L to have been consistent with the staff, it should have selected 8% instead of 4.5%.

The staff's nominal discount rate of 15% is based on a cost of common equity which is higher than that recommended by any other party to the proceeding. However, the staff explicitly pointed out that the 15% nominal cost of capital should be considered a lower bound for the proper nominal discount rate to be used in this proceeding.

On balance, we believe that the staff LRIC study develops and uses a more realistic carrying charge than PP&L. It is our opinion, therefore, that for rate spread purposes the staff's discount rate would result in electricity user's paying closer to the same amount in real terms for each year that a given facility is in use.

Another significant difference between the two LRIC studies relates to PP&L's providing a 15% reserve margin by adding a gas turbine, whereas the staff did not allow for such an addition. We agree with the staff's position on this point which is stated in Exhibit 40, as follows:

> "PP&L added a 15% reserve margin to the long-run incremental unit cost where staff did not. The 15% reserve margin was not used because the combustion turbine is used to determine the demand component of a coal plant. Since there was no reserve margin used in the calculation of the coal plant, staff felt that this was inconsistent."

B. <u>Allocation to Customer Classes</u>

Both PP&L and the staff calculate marginal customer costs for each class of customer. The staff, however, in using its study in preparing its LRIC studies for spreading the revenue requirement among the customer classes, does not include marginal customer costs and recognizes only marginal energy and demand as appropriate cost elements for their purposes. PP&L takes exception to this treatment, arguing that customer costs were actually incurred by the utility in providing service, and that they varied by customer class. PP&L argues that the impact of ignoring customer costs in the rate spread process results in unfairly removing a bona fide revenue requirement burden from some customer classes and placing it on others.

The staff rationale for excluding customer costs from the rate spread determination is that customer costs do not vary with the demands customers place on the system (at different time-of-use periods) and are therefore inappropriate to include for this purpose. This staff view coincides with the treatment we have adopted in electric rate cases with some degree of consistency over the past several years. While the evidence shows that in PP&L's case these customer costs when expressed on a per-customer basis vary by customer load classes, this does not mean that such costs are load related.

On each of the points of major difference between the utility and the staff LRIC studies, the weight of the evidence supports the staff's study as possessing greater merit for purposes of this proceeding. Accordingly, we will use the staff's LRIC study as the basis for allocating costs among customer classes and for the design of rates. However, to moderate rate changes between classes of service, we will only move a portion of the way toward an incremental cost allocation in this proceeding (20% incremental cost weight: 80% system average percentage weight). Due to the incomplete showing as to the proper development of incremental costs to be applied to irrigation (PA-20) customers, we will simply maintain the relationship between PA-20 rates and the overall system rate by allocating revenues to this class based entirely on the system average percentage increase.

C. Rate Design

1. Residential Rates

Section 739 of the Public Utilities Code, as amended in 1982 by the Sher Bill, provides among other things, that the Commission shall establish a "base level quantity" of electricity for residential customers in the order setting rates issuing from the first general rate proceeding for an electric utility decided on or after January 1, 1983 with an effective date of not earlier than January 1, 1984. Pending that effective date, existing lifeline allowances are to remain in effect.

As used in amended § 739:

> "'Baseline quantity' means a quantity of electricity or gas for residential consumption customers to be established by the commission based on from 50 to 60 percent of average residential consumption of these commodities, taking exception that, for residential gas customers and for all-electric residential customers, the baseline quantity shall be established at from 60 to 70 percent of average residential consumption during the winter heating season. In establishing the baseline quantities, the commission shall take into account climatic and seasonal variations in consumption and the availability of gas service. The commission shall review and revise baseline quantities as average consumption patterns change in order to maintain the 50 to 60 percent ratio these ratios."

The Sher Bill also requires the Commission to establish a special medical baseline allowance for life-support requirements. The Commission handled this requirement of the Sher Bill on an industry-wide basis by opening OII 83-01-01 for this purpose. D.84-01-064 in that investigation determined the amount of this special medical allowance for the entire state, and we will implement the medical allowance for PP&L in this decision. As developed in D.84-01-064, the effect of this allowance on the utility's results of operations is inconsequential, and it will not be given consideration in the adopted results for the test year.

Table 3 shows the relationship between the range of baseline quantities permitted by the Sher Bill, the PP&L and staff proposed baseline allowances and present lifeline allowances.

TABLE 3

Comparison of Baseline Quantity Proposals

Areas	Type of Service	Season	Permissible Range(50-60%) kWh	Proposed Range PP&L %	Proposed Range Staff %	Present Lifeline kWh
Del Norte County	Basic	S		55	50	240
	Basic + WH*		420-530	55	50	490
	Basic + SH*		550-680	51	50	240
	All Electric		550-680	50	50	490
	Basic	W		55	50	240
	Basic + WH*		520-660	55	50	490
	Basic + SH*		1160-1430	65	65	1080
	All Electric		1160-1430	65	65	1330
All Other Areas	Basic	S		55	50	240
	Basic + WH*		420-530	55	50	490
	All Electric		550-680	51	50	240-490
	Basic	W		55	50	240
	Basic + WH*		520-660	55	50	490
	Basic + SH*		60-70	65	65	1360
	All Electric		1160-1430	65	65	1610

* WH = water heating; SW = space heating

It can be seen from Table 3 that the staff proposes separate baseline quantities for the winter and summer seasons, whereas PP&L does not. Otherwise, there is little difference between the recommendations of PP&L and the staff.

The staff proposal differs from the utility's in two respects. First, the staff recommends that separate summer and winter baseline quantities be established for all residential customers, not just those with electric space heating as proposed by the utility. We believe the staff is correct in making this recommendation because the measured average consumption of residential users increases 24% during the winter season.

Second, the staff recommends that baseline quantities be set as a percentage of recent historic consumption normalized to adjust for unusual weather conditions. PP&L did not normalize recorded consumption and accordingly recommended higher quantities for some classes of users. We are of the opinion that the use of normalized consumption data as recommended by the staff will result in more stable baseline quantities to the benefit of the ratepayers.

The staff recommends that Del Norte County be treated as a separate climate zone from the rest of PP&L's service territory for the purposes of setting baseline quantities. Both Del Norte and the rest of PP&L's service territory would receive the same total annual baseline allocation under the staff's proposal, but Del Norte's winter allocation would be spread over eight months whereas the winter season for the rest of the service area would be only six months. We approve of this treatment, which is consistent with our prior determinations on PP&L's lifeline quantities in D.92411.

The Sher bill requires that baseline quantities be priced at 15-25% below the system average rate. The baseline quantity thus constitutes the first block of an increasing block rate structure.

The staff recommends retaining PP&L's existing two-block rate structure for residential rates with the baseline rate at 80% of the system average rate as described in Exhibit 40. The staff also studied the impacts of setting baseline rates at 75% and 85% of system average rates. We have reviewed these staff recommendations, as well as those of PP&L, and we conclude that the 80% factor favored by the staff is a fair and reasonable level at which to fix baseline quantity rates.

2. General Commercial <u>and Industrial Rates</u>

The bulk of PP&L's commercial and industrial customers are served under two schedules: Schedule A-32 for demands of up to 100 kW and Schedule A-36 for demands of between 100 and 500 kW. These schedules provide for three types of charge: basic charge, demand charge, and energy charge. The basic charge is determined from the average of the two highest monthly demands of the preceding year. Its purpose is the recovery of a portion of billing and commitment expenses. The demand charge reflects the fixed and variable costs related to load on the system. The energy charge reflects the fixed and variable costs which are a function of the energy use.

The staff believes that these two rates do not appropriately reflect the LRIC associated with the different classes of small and medium-sized customers. The staff therefore recommends that the Commission: (1) create a new schedule to be designated A-32A for low demands; and (2) modify Schedules A-32 and A-36 and eventually merge them into one schedule. Under the staff proposal, Schedule A-32A would be mandatory for customers with demands smaller than 20 kW and optional for demands between 20 kW and 500 kW. Current rates do not reflect the sharp change in LRIC that occurs for demands in the range of 15 to 20 kW.

PP&L does not favor creation of the new Schedule A-32A. The utility proposes that the higher LRIC of serving customers with demands lower than 20 kW be accommodated by retaining the present declining-block energy-rate structure of Schedule A-32. The staff opposes the perpetuation of declining-block rate structure of Schedule A-32 on the grounds that such a rate structure provides a disincentive for conservation.

The higher LRIC incurred in serving low- and medium-demand customers results from their different demand costs. We agree with the staff that it is not appropriate to recover these costs through a schedule with a declining-block energy-rate structure. We share the staff view that the better way of collecting higher-per-kW charges from low-demand customers would be through a new rate schedule for customers having demands lower than 20 kW. We believe that such a new schedule would allow PP&L to bill these low demand customers in proportion to the LRIC of serving them. We are not persuaded by PP&L's argument that the record does not contain LRIC data which distinguishes between demand levels above and below the specific point of 20 kW. The 20-kW breaking point chosen by the staff has the distinct cost advantage of being the minimum demand level at which PP&L typically installs a demand meter. Therefore, we see no advantage in using 15 kW as the breaking point merely because more precise LRIC data might be available to us in this record.

The staff questions the current use of 100 kW as the breaking point in demand between two rate schedules, i.e., Schedules A-32 and A-36, especially if this decision adopts a separate schedule for customers having demands below 20 kW. PP&L's study, Exhibit 14, shows very little difference in LRIC for customers with demands in the range of 15 to 100 kW with those in the range of 100 to 500 kW. The staff further brings out that in actual practice the two schedules do not, in fact, segregate customers at the 100-kW point. Exhibit 14 shows that 62% of PP&L's customers on Schedule A-36 have demands below 100 kW and that a number of customers on Schedule A-32 have demands above 100 kW. The staff, therefore, proposes the merging of the two schedules on a delayed basis to avoid a sudden extraordinarily large rate increase for certain customers from the combined impact of the general rate increase and the change in rate structure.

PP&L is against the creation of the new Schedule A-32A, but it does not oppose the concept of moving toward the merging Schedules A-32 and A-36. The utility is concerned however, that this order may not provide either sufficient time to address all the ramifications of the staff proposal or time to minimize the impacts of the rate design changes on affected customers. PP&L recommends, therefore, if the Commission orders the consolidation, that the two schedules remain separate for the present and that the consolidation be made effective through an advice letter filing to be filed within three months of the final order in this proceeding. PP&L reasons that such an interval would afford it and the staff time to work out a mutually acceptable rate design which would minimize impacts on its customers and its own administrative machinery.

PP&L states that if the new Schedule A-32A is placed in effect prior to the consolidation of Schedules A-32 and A-36, there would thus be provided three optional schedules for customers with over 20 kW demand. PP&L says that its computer capabilities cannot calculate three optional rates and that, therefore, each customer account would have to be individually reviewed by hand. Pacific contends that it would be discriminatory to make this schedule, as suggested by the staff, optional for some customers (over 20 kW) and mandatory for others (under 20 kW).

We share PP&L's concerns. In ordering the establishment of Schedule A-32A and the move toward consolidation of Schedules A-32 and A-36, the adopted tariffs will provide for a 90-day period in which to overcome the problems which would otherwise arise from the rate structure change. The general commercial rates which will become operative on the effective date of this order will, therefore, not reflect an immediate change in the structure, i.e., Schedules A-32 and A-36 will be continued in their present form, and their consolidation and the creation of Schedule A-32A will be delayed until we approve the advice letter filing.

We will eliminate the 100-kW minimum demand charge, but, in order to avoid revenue instability and administrative problems during the period of time prior to consolidation of the A-32 and A-36 schedules, the tariffs will leave in effect that demand charge on service provided under Schedule A-36. The increase will be applied to the energy rate only. For the 90-day interim period during which: (1) rates for Schedule A-32 will be developed that more closely follow the rates for Schedule A-36, and (2) Schedule A-32A will be established for customers with demands of 20 kW or less, the demand and energy charges on Schedule A-32 will be increased by the same percentage. Basic charges will be kept at the same level.

3. <u>Time-of-Use Rates</u>

Customers with demands of 500 kW and greater are billed under Schedule AT-48, which provides for the same charges as Schedules A-32 and A-36, except that the demand charge varies by season and it is applied only for demand during the peak period from 6:00 a.m. to 10:00 p.m. Schedule AT-48 has a minimum demand charge based on 50% of the highest demand occurring during the season or 300 kW, whichever is greater.

PP&L proposes to increase the demand and energy charges on this schedule by the same percentage and maintain the basic charge at its current level. The staff generally supports this proposal; however, it recommends abolishing the ratchet and minimum demand charge. The staff believes that the minimum demand charge reduces customer incentive to minimize demand below a previous peak and that there is no incentive whatsoever to lower demand below 300 kW. The staff contends that the basic charge of this schedule already functions as a minimum demand charge because it is computed on the average of the two highest months' demands experienced during the previous twelve months.

Consistent with our position in SDG&E's Test Year 1984 General Rate Case, we will adopt staff's proposal which eliminates "demand rackets" and minimum demand charges. We also eliminated SCE's minimum demand charges in D.92549 and Sierra Pacific Power's in D.83-04-066.

No changes were proposed in this proceeding by the utility or the staff for the reactive power charge or the voltage adjustment. Staff recommends, and we concur, that PP&L be required to file with their next general rate case, a study showing the different costs incurred for different voltage levels and power factors.

4. Commercial Water Heating

Service is provided to commercial water-heating customers under Schedule AWH-31, which has been closed to new customers since 1975. The rates provided by this schedule are approximately 35% below the weighted average of rates for service under the general commercial Schedules A-32 and A-36. PP&L recommends that Schedule AWH-31 receive the system average increases. On the other hand, the staff does not believe there is good reason to maintain the present subsidy. It recommends, however, that the level of Schedule AWH-31 be moved only half way toward the weighted average of Schedules A-32 and A-36 because any further adjustment at this time would impose an unjustified burden on the remaining water-heating customers. We adopt the staff position.

5. Irrigation Service

Irrigation customers are severed under Schedule PA-20, which includes three types of charges: (1) a winter demand charge based on the maximum demand occurring during each winter month, or, for smaller demands, the nameplate horsepower of the connected load; (2) an annual charge collected in November, based on the average of the two highest demands established during the previous 12-month period; and (3) declining block energy rates differentiated by season.

PP&L would maintain the annual charge at its current level and increase the demand and energy charges by equal percentages. This approach, which the staff believes is reasonable, would maintain the proportional relationship between the seasonal charges. The staff would, in addition, move the declining-block energy rates of the schedule toward a single block to increase the incentive for conservation.

The CFBF asserts that for California agriculture to remain economically sound and competitive with Oregon agriculture, the Commission must, as it did in D.82-05-42, set irrigation rates at the residential baseline rate. The CFBF points out that PP&L provides its Oregon agricultural customers a credit of 1.4 cents per 1983 seasonal kWh in excess of 1982 seasonal kWh. CFBF contends that this Oregon arrangement has the effect of creating a lower price and increasing the amount of irrigation pumping, and that it will work to the economic detriment of California's agriculture unless

California's farmers are allowed to remain competitive by our keeping irrigation at the residential baseline rate. It also urges that we require PP&L to institute the same type and style of agricultural pumping service seasonal credit in California as it is now offering in Oregon.

We will adopt PP&L's proposal as modified by the staff. In so doing we are mindful of the concerns of the CFBF, and we will maintain irrigation rates at the lowest level that reasonable considerations of cost and equity will permit. The record will not, however, support the establishment of an agricultural pumping seasonal credit as urged by CFBF.

6. Streetlighting Service

There is no difference between the rate design of PP&L and the staff for the several streetlighting schedules. Both propose increasing all outdoor and streetlighting schedules on an equal amount per kWh. In addition, the staff recommends modifying Schedules LS-57 and LS-58 to remove reference to lamp types which have been completely replaced by sodium-vapor lamps.

We will adopt the recommendations of PP&L and the staff.

D. Comparative Rates

Congressman Bosco, the CFBF, other farmer groups, individual farmers and other consumers raise the issue of comparable rates. They point to PP&L's lower rates in its service area across the Oregon border. Unfortunately, we cannot simply set California rates at the Oregon level. To do so would constitute a confiscatory act on our part. A number of concrete factors contribute to the lower cost of service in PP&L's Oregon service areea, not the least of which is the Northwest Power Act which provides wholesale electric power to PP&L at preferential rates for resale to its Oregon customers. That act of Congress does not permit extending the preferential treatment to PP&L's California customers.

Pertinent to the issue of comparable rates, is the fact that PP&L's customers enjoy the lowest rates of any investor-owned electric utility serving in California. Also pertinent to this issue are the results of a recent nationwide survey conducted by the National Association of Regulatory Utility Commissioners (NARUC)[7] in 216 public utility service areas throughout the United States. Only one California area appears among the 25 territories having the lowest charges for consumption of 500 kWh per month. It is PP&L's Crescent City service area. It ranks as number 200, with only 16 of the 216 areas surveyed throughout the nation having lower electricity charges than Crescent City.

XII. NOTICE TO THE PUBLIC

Two issues relating to adequacy of notice to the public were raised in the latter part of the hearings in this proceeding. The first issue concerns the amount of the increase ($10.8 million) which PP&L is seeking in the combined applications, and whether the public has been properly placed on notice for that figure or for merely the increase requested in the first application ($6.0 million). The second issue concerns whether the public has been afforded adequate opportunity to participate in the consideration of the effects of nuclear project abandonment in this general rate increase proceeding.

7 Official notice is taken of the NARUC's 1983 Summer Survey of Residential Bills, which compares electricity charges during the three-month period June through August 1983 for major investor-owned utilities in 49 states and the District of Columbia.

A. Amount of the Requested Increase

It is, and has been throughout these proceedings, PP&L's position that the amount of the general rate increase requested in the two applications is the sum of the amounts requested in A.83-05-052 and A.83-07-17. The additive nature of the applications was not questioned during the first part of these proceedings, certainly not at the prehearing conference nor at the four days of public witness hearings held in the utility's service area at Crescent City and Yreka. The record conclusively shows that the presiding ALJ, staff counsel, the interested parties, and the participating public were proceeding on the basis and understanding that the amount of the rate increase at issue is $10.8 million, not just the lesser amount of $6.0 million requested in the first application.

At more or less the midpoint of these proceedings, staff counsel perceived the issue now before us. He does not contest the adequacy of notice for each of the two applications. Indeed, no one does, and this aspect of notice is not at issue. The thrust of staff counsel's position is that the general rate increase request now before us is for $6.0 million, that the ERAM request for $4.8 million is not properly added to the $6.0 million general rate increase request; and that the public has been duly noticed only for an increase of $6.0 million.

With the notice requirements of the PU Code particularly in mind, we have carefully reviewed the content of the two applications and the notices that were given to the public respecting each application. We have further reviewed the full record of the proceeding in this light. We are of the opinion that the consolidated applications constitute a properly filed request for a $10.8 million general rate increase and that the public was adequately notified in a timely manner.

B. Abandoned Nuclear Projects

Congressman Bosco and TURN contend that the public did not receive sufficient notice as to the inclusion in this proceeding of issues relating to the revenue requirement effects of the abandonment of the two nuclear projects in which PP&L was a participating utility. The Congressman and TURN are certainly correct on the technical point that neither of the applications as filed in this rate proceeding specifically treat the issues relating to the abandonment of these projects.

It is a ratemaking reality that the issues and elements that add up to a utility's total revenue requirement are constantly being modified, added to, or deleted from during the course of an extended rate increase proceeding such as this. It would be impractical and self-defeating to proceed otherwise. So long as the duly noticed total revenue requirement sought is not exceeded, it is more often than not necessary for us to recognize and evaluate the effects of events and circumstances occurring subsequent to the filing of a rate increase application. Our issuance of D.83-11-012 in A.82-07-048, supra, is one of a number of such occurrences which have been considered by us in this proceeding without thereby exceeding notice requirements.

In the above respect, nothing unusual attaches to this issue. However, the issues relating to the abandoned projects have been before us and in the public's eye and mind ever since PP&L filed A.82-07-048 on July 7, 1982. That application requested authority to increase PP&L's California electric rates to recover its investment in two abandoned generating projects. Hearings to receive public testimony were held in Yreka and Crescent City on March 17, 1983 and

March 18, 1983 respectively. As we noted in D.83-11-012, more than 80 members of the public made statements at the hearings, including a number of public officials. Evidentiary hearings were held in San Francisco during April of 1983, and the matter was taken under submission on June 13, 1983.

As discussed previously in this opinion, late in the course of this general rate proceeding, on November 2, 1983, we issued D.83-11-012, which stated that although traditional ratemaking may have justified recovery of PP&L's investment in the two terminated projects, direct recovery by amortization through rates would be denied. The decision noted, however, that Oregon had allowed an offset of the expenditure for one project with the gain from a securities transaction and that Washington had increased the return on common equity by an additional 2.5%. The decision ordered that the issue of risk to shareholders associated with the denial of amortization be considered in this general rate case proceeding. D.83-11-012 was subsequently modified by D.84-05-097 which affirmed the denial of recovery of PP&L's investment. That decision is currently on appeal and subject to Commission reconsideration.

The ALJ, on November 15, 1983, issued and sent to all parties a written ruling stating that the issues as to the effects of D.83-11-012 on PP&L's return on common equity would be considered during the hearings in this proceeding. At the conclusion of the hearings, oral arguments were presented before the assigned Commissioner and the ALJ. All parties were given an opportunity to mail, by January 6, 1984, briefs limited to the issue of compensation for the increased risk caused by denial of direct amortization of Pacific's investment in the two terminated nuclear projects.

Our review of the handling of this issue gives us no basis for concluding that the notice requirements of the PU Code have been violated. In our opinion, it is properly before us as an issue relating to PP&L's revenue requirement for the test year 1984. However, because D.84-05-097 is an appeal, we leave the issue open.

XIII. MINORITY/FEMALE BUSINESS ENTERPRISE PROGRAM

In D.82-12-101, we announced our intention to review the adequacy of each utility's minority/female business enterprise (M/FBE) program as part of the general rate case process. Pursuant to our order, PP&L has filed certain information regarding its M/FBE program. Our Revenue Requirements Division staff has reviewed PP&L's filing and is of the opinion that it basically complies with D.82-12-101.

In D.84-06-101, our recent decision in the Pacific Bell general rate case, we considered the reporting format recommended by staff and concluded that greater specificity was needed. We required Pacific Bell to report its M/FBE data according to the ethnic classifications used by agencies of the State of California and to break out total contract expenditures and M/FBE contracts for each category in which $5 million of business or more was done in a prior year. We also required Pacific Bell to establish M/FBE goals for 1986 and to file semiannual reports as a means of tracking the company's progress. Pacific Bell was directed to meet with minority group representatives in implementing our decision. We would like PP&L to follow a similar procedure and will direct it to do so in our order.

XIV. FINDINGS AND CONCLUSIONS

A. Findings of Fact

1. By these applications PP&L requests increased rates for its California service territory to yield an aggregate increase in operating revenues of $10,873,000 based upon the test year 1984.

2. PP&L also requests authority to file for a rate increase by advice letter for the year 1985 to compensate it for any attrition of earnings.

3. These applications were duly noticed, and all interested parties were afforded an opportunity to be heard on the issues before us.

4. The relative use method of jurisdictional allocation sponsored by the staff is reasonable to use in this proceeding for purposes of determining PP&L's California revenue requirement for the test year 1984.

5. The amounts of operating revenues, operating expenses, and rate base, as well as each element thereof, shown on Table 2 - Summary of Results of Operations, and the method used in obtaining these amounts as discussed in the opinion, represent a fair and reasonable determination of revenue requirement for PP&L's California operations for the test year 1984.

6. The proper and reasonable level of PP&L's California jurisdictional revenue requirement for the test year is $50.9 million.

7. Present rates are estimated to produce $44.2 million in 1984. PP&L is entitled to a rate increase of $6.7 million, which will produce operating revenues of $50.9 million during the test period.

8. For purposes of determining test year 1984 rate of return it is reasonable to impute the following capital structure to PP&L: 52% long-term debt; 12% preferred stock, and 36% common equity.

9. A cost of long-term debt of 9.86% and a cost of preferred stock of 10.92% are reasonable for test period purposes.

10. No consideration should be given to the effects of the abandoned nuclear projects in determining the cost of common equity capital to PP&L for the test period while the appeals to D.84-05-097 are pending.

11. The reasonable cost of common equity to PP&L for the test period is 15.50%.

12. A rate of return of 12.02% is fair and reasonable to apply to PP&L's rate base to obtain net operating revenue for the 1984 test year and 1985 attrition year.

13. Estimated revenues based on the sales forecast for test year 1984 and attrition year 1985 are subject to significant fluctuation.

14. Because of the difficulties inherent in estimating test year electricity sales and the need to protect the ratepayer and the utility from an incorrect estimate, it is reasonable to establish an ERAM for electric sales.

15. The purpose of the ERAM authorized here is to offset the effects of inaccurate estimating. It is not intended to offset the effects of the so-called billing lag which occurs during the first month that a rate increase is effective.

16. A factor contributing to inaccuracy in estimating electricity sales is the difficulty in quantifying the effects of conservation.

17. The adoption of an ERAM will minimize any disincentive toward PP&L's promotion of cost-effective conservation programs.

18. The ERAM tariff provisions shown in Appendix B are reasonable.

19. PP&L's conservation programs as funded for the test period will promote conservation and they are in the public interest.

20. The procedure adopted here provides a reasonable method of treating underspent funds authorized for conservation/load management programs.

21. The adopted level of funding for PP&L's conservation programs is reasonable for test year 1984.

22. It is equitable that changes in electric rates for each major customer group reflect the cost to the utility of furnishing the last increment of additional system supply.

23. Directing rates for marginal usage by each major customer group toward the cost to the utility of furnishing an additional unit of system supply will provide appropriate signals to customers of the cost of added energy consumption and will provide the appropriate incentive for conservation.

24. Marginal costs provide the acceptable approach to allocating cost recovery among customer groups because they provide a clear pricing signal relating to a customer's conservation measures and are in keeping with PURPA standards.

25. Application of marginal costs for allocation of adopted cost recovery by customer group should be tempered by judgment and experience rather than simply relying on a statistical approach.

26. Long-run incremental costs provide a more reasonable basis for PP&L for allocating revenues among customer classes and rate design purposes because of PP&L's system characteristics.

27. The staff's rate design, as modified by our determinations, is fair and reasonable.

28. The increase in rates and charges authorized by this decision is justified and is reasonable; the present rates and charges, insofar as they differ from those prescribed by this decision, are for the future unjust and unreasonable.

29. The rate schedules set forth in Appendix C of this decision will afford PP&L an opportunity to collect the additional authorized revenues in a just, reasonable, and nondiscriminatory manner.

30. The allocation of revenues and design of these rates set forth in Appendix C reasonably reflect the staff's LRIC study, and the rates substantially follow the rate design recommended by the staff, except as noted in the opinion portion of this decision.

31. The staff's calculation of the net-to-gross multiplier is reasonable.

32. The expectation is that PP&L will be unable to earn its authorized return on common equity in attrition year 1985 without an attrition allowance to offset increases in operating costs resulting from continuing high levels of inflation, and an increase in rate base.

33. PP&L may require additional revenues in attrition year 1985 for its California jurisdictional electric operations if the utility is to earn its authorized return on common equity.

34. The joint company and staff recommendation of the use of the Fall 1984 DRI forecast as an attrition methodology is reasonable. It is also reasonable to establish the amount of the revenue adjustment required during the attrition year by an appropriate advice letter filing in the fall of 1984.

35. The rates adopted in this decision comply with the requirements of § 739 of the PU Code amended by the Sher Bill.

36. The Minority/Female Business Enterprise program as modified in the above decision is reasonable.

B. Conclusions of Law

1. PP&L should be authorized to file the revised electric rates which are set forth in Appendix C and which are designed to produce $6.7 million in additional base rate revenues based on the adopted test year 1984 results of operations.

2. PP&L should be authorized to file revised electric rates designed to produce base rate revenues in the attrition year 1985 in an amount to be determined in October 1984.

3. PP&L should be authorized to file ERAM provisions in its tariffs substantially in the form shown in Appendix B.

4. PP&L should be authorized and directed to make such other changes in its filed tariffs as are set forth in Appendices B and C.

5. The effective date of this order should be the date on which it is signed to meet PP&L's need for immediate rate relief and because a substantial portion of the test year has elapsed.

6. All motions not previously ruled upon should be denied.

O R D E R

IT IS ORDERED that:

1. Pacific Power and Light Company (PP&L) is authorized and directed to file with this Commission, on the effective date of this order, revised tariff schedules for electric rates as set forth in attached Appendices B and C.

2. The revised tariff schedules shall become effective on the date of filing and shall comply with General Order 96-A.

3. All motions not previously ruled upon are denied.

4. PP&L shall carry over into the attrition year 1985 any conservation funding allowed in the test year which remains unexpended at the end of 1984.

5. Before January 1, 1985, PP&L shall file a report with this Commission stating its Minority/Female Business Enterprise goals for calendar years 1985 and 1986. Commencing in 1985, on March 1 and October 1 of each year, PP&L shall file a report on the progress made by its M/FBE program. The March 1 report shall cover program activity from July 1 through December 31 of the previous year and the October 1 report shall cover activity from January 1 through June 30. The semiannual reports shall present M/FBE data according to the ethnic classifications used by agencies of the State of California and by contract categories in which $150,000 of business or more was done in the prior year. PP&L shall meet and confer with minority group representatives in preparing their goals and reporting procedures.

6. PP&L is instructed to file an advice letter on or before October 15, 1984, setting forth the changed revenue requirement as a result of its changed expenses and capital costs.

7. That portion of A.83-07-17 which requests adjustment in ERAM to recover lost sales revenues resulting from the fact that actual sales were less than the adopted sales in PP&L's last general rate case is denied. That portion which requests establishment of an ERAM account is granted.

8. A.83-05-52 is granted in part and denied in part.

This order is effective today.

Dated July 18, 1984, at San Francisco, California.

I will file a written dissent.

PRISCILLA C. GREW
Commissioner

I will file a written concurrence.

LEONARD M. GRIMES, JR.
President
VICTOR CALVO
DONALD VIAL
Commissioners

LEONARD M. GRIMES, JR.
President
VICTOR CALVO
DONALD VIAL
WILLIAM T. BAGLEY
Commissioners

APPENDIX A

List Of Appearances

Applicant: Leonard A. Girard and Nancy M. Ganong, Attorneys at Law, for Pacific Power and Light Company.

Interested Parties: Messrs. Zupanlic & Doolittle, by Allen R. Crown, Steven A. Geringer, and Antone S. Bulich, Jr., Attorneys at Law, for California Farm Bureau Federation; Michel Peter Florio, Attorney at Law, for Toward Utility Rate Normalization (TURN); Robert Innes, for Congressman Bosco; and Wayne T. Criss, for Siskiyou Cattlemen's Association and Klamath Basin Hay Growners.

Commission Staff: James E. Scarff, Attorney at Law, and David K. Fukutome.

(END OF APPENDIX A)

APPENDIX B
Page 1

Electric Revenue Adjustment Mechanism (ERAM)

No. 1 - Purpose:
The purpose of this Electric Revenue Adjustment Mechanism (ERAM) is to adjust revenues for sales fluctuations.

No. 2 - Applicability:
This ERAM provision applies to all bills for service under all rate schedules and contracts for electric service subject to the jurisdiction of the Commission.

No. 3 - Base Rates:
The Base Rates are the rates for electric service in effect at any time, exclusive of adjustment rates for which a balance or adjustment account is specifically provided in the Preliminary Statement.

No. 4 - Base Revenue Amount:
The Base Revenue Amount is the annual revenue to be collected from Base Rates. The base revenue amount shall be increased or decreased to incorporate changes in the level of authorized revenue specified in decisions of the Commission with respect to Base Rates concurrently with the beginning of the period to which such revenue applies.

No. 5 - Revision Dates:
The Revision Dates are January 1 and July 1 of each year. On such dates or as soon thereafter as the Commission may authorize, the Utility shall, in accordance with the provisions hereof, place into effect an increase or decrease in the ERAM Adjustment Rate then in effect. Unless otherwise authorized or ordered by the Commission, such increases or decreases shall be made not more than twice in any calendar year.

No. 6 - Electric Revenue Adjustment Account:
Beginning as of July 18, 1984, the Utility shall maintain an Electric Revenue Adjustment Account. Entries shall be made to this account at the end of each month as follows:

(a) A debit entry equal to, if positive (credit entry, if negative):

(1) The applicable Base Revenue Amount, multiplied by the applicable monthly factor from the table below, less.

(2) The amount of Electric revenue for service rendered during the month at Base Rate.

January	0.089	April	0.077	July	0.092	October	0.072
February	0.083	May	0.082	August	0.090	November	0.082
March	0.078	June	0.087	September	0.076	December	0.092

(b) A credit entry equal to the revenue from all applicable sales for service rendered during the month at ERAM rates if positive (debit entry, if negative).

(c) An entry equal to interest on the average of the balance in the account after entries (a) and (b) above at the interest rate of 1/12 of the most recently available months interest rate on Commercial Paper (prime, 3 months) published in the Federal Reserve Stat. Release.

No. 7 - ERAM Rate:

The ERAM rate shall be equal to the estimated balance in the Electric Revenue Adjustment Account as of the revision date divided by the estimated sales for the six-month period beginning with the revision date. The ERAM Rates shall be added to the rates otherwise in effect and shall be separately identified in each rate schedule.

No. 8 - Time and Manner of Filing and Related Reports:

The Utility shall file a revised ERAM Rate with the California Public Utilities Commission at least 30 days but not more than 90 days prior to the Revision Date. Each such filing shall be accompanied by a report which shows the derivation of the rate to be applied.

(END OF APPENDIX B)

A.83-05-052
A.83-07-017

Schedule No. A-32

APPENDIX C
Page 1

GENERAL SERVICE

APPLICABILITY

Applicable to single-phase or three-phase alternating current electric service, at such voltage as the Utility may have available at the customer's premises, for all purposes except those for which specific schedules are provided. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. A written agreement shall be required for application of this schedule to service furnished for intermittent or highly fluctuating loads. Not applicable to service for use in parallel with, in supplement to, or in standby for customer's electric generation or other energy sources.

TERRITORY

Within the entire territory served in California by the Utility.

MONTHLY BILLING

The Monthly Billing shall be the sum of the Basic, Demand, Energy, and Reactive Power Charges; plus Delivery and Metering Adjustments.

Basic Charge:

If Load Size Is:	The Monthly Basic Charge Is: Single Phase	Three Phase
20 kw* or less	$5	$8
Over 20 kw*	$5 plus $1 per kw* for each kw* in excess of 20 kw	$8 plus $1 per kw* for each kw in excess of 20 kw*

*Note: Kw load size, for determination of the Basic Charge, shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Demand Charge:

No charge for the first 100 kw of Billing Demand.
$.71 per kw for each kw of Billing Demand in excess of 100 kw.

Energy Charge:

Base Rate	ERAM Adjustment	Net Rate	
8.914¢	0.00¢	8.914¢	per kwh for the first 6,000 kwh plus 75 kwh per kw for each kw of Billing Demand in excess of 20 kw
6.815¢	0.00¢	6.815¢	per kwh for all additional kwh.

(Continued)

A.83-05-052
A.83-07-017

Schedule No. A-32

APPENDIX C
Page 2

GENERAL SERVICE
(Continued)

Minimum Charge:
The Monthly Minimum Charge shall be the sum of the Basic Charge and the Demand Charge for the current month. A higher minimum may be required under contract to cover special conditions.

Reactive Power Charge:
The maximum 15-minute integrated reactive demand in kilovolt-amperes occurring during the month in excess of 40% of the maximum measured 15-minute integrated demand in kilowatts occurring during the month will be billed, in addition to the above charges, at 60¢ per kva of such excess reactive demand.

BILLING DEMAND
The Billing Demand shall be the maximum measured 15-minute integrated demand in kilowatts occurring during the month. At the Utility's option, a demand meter will be installed when the Utility estimates that a customer's demand may exceed 20 kw per month. The maximum demand shall not be less than the diversified resistance welder load computed in accordance with Rule No. 21-2-b.

CONTINUING SERVICE
Except as specifically provided otherwise, the rates of this tariff are based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a seasonal customer from minimum monthly charges.

TERM OF CONTRACT
Not less than one year.

SPECIAL CONDITIONS
For commercial buildings, apartment houses, court groups, auto camps, and the like, for which individual customers are submetered, the charge to individual customers must be at the Utility's regular tariff rate for the type of service which such individual customer may actually receive.

RULES AND REGULATIONS:
Service under this schedule is subject to the General Rules and Regulations contained in the tariff of which this schedule is a part and to those prescribe by regulatory authorities.

A.83-05-052
A.83-07-017

Schedule No. A-36

APPENDIX C
Page 3

LARGE GENERAL SERVICE - Optional
100 KW AND OVER

APPLICABILITY

Applicable to electric service loads which have not registered 500 kw or more, more than once in any consecutive 18-month period. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. A written agreement shall be required for application of this schedule to service furnished for intermittent or highly fluctuating loads. Not applicable to service for use in parallel with, in supplement to, or in standby for customer's electric generation or other energy sources.

TERRITORY

Within the entire territory served in California by the Utility.

MONTHLY BILLING

The Monthly Billing shall be the sum of the Basic, Demand, Energy, and Reactive Power Charges; plus Delivery and Metering Adjustments.

Basic Charge:

If Load Size Is:	The Monthly Basic Charge Is:
100 kw* or less	$215
101 kw* - 300 kw*	$ 58 plus $1.57 per kw*
Over 300 kw*	$184 plus $1.15 per kw*

*Note: Kw load size, for determination of the Basic Charge, shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Demand Charge:

$1.50 per kw for each kw of Billing Demand.

Energy Charge:

Base Rate	ERAM Adjustment	Net Rate
5.099¢	0.00¢	5.099¢ per kwh for all kwh.

Minimum Charge:

Monthly Minimum Charge shall be the Basic Charge plus the Demand Charge for the current month. A higher minimum may be required under contract to cover special conditions.

(Continued)

A.83-05-052
A.83-07-017

Schedule No. A-36

APPENDIX C
Page 4

LARGE GENERAL SERVICE - Optional
(Continued)

BILLING DEMAND

The billing demand shall be the greater of the following:

(a) the maximum measured 15-minute integrated demand in kilowatts occurring during the month,
(b) the diversified resistance welder load computed in accordance with Rule No. 21-2-b, or
(c) 100 kw.

CONTINUING SERVICE

Except as specifically provided otherwise, the rates of this tariff are based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a seasonal customer from minimum monthly charges.

TERM OF CONTRACT

Utility may require customer to sign a written contract which will have a term of not less than five years.

RULES AND REGULATIONS:

Service under this schedule is subject to the General Rules and Regulations contained in the tariff of which this schedule is a part and to those prescribed by regulatory authorities.

A.83-05-052
A.83-07-017

Schedule No. AT-48

APPENDIX C
Page 5

LARGE GENERAL SERVICE - METERED TIME OF USE
500 KW AND OVER

APPLICABILITY

This schedule is applicable to electric service loads which have ever registered 500 kw or more, more than once in any consecutive 18-month period. This schedule will remain applicable until customer fails to equal or exceed 500 kw for a period of 36 consecutive months. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads will be provided only by special contract for such service.

Partial requirements service for loads of 500 kw and over will be provided only by application of the provisions of Schedule AT-47.

TERRITORY

Within the entire territory served in California by the Utility.

MONTHLY BILLING

The Monthly Billing shall be the sum of the Basic, Demand, Energy, and Reactive Power Charges; plus Metering and Delivery Adjustments.

Basic Charge:

If Load Size is:	The Monthly Basic Charge is:
1,000 kw* or less	$360 plus $.80 per kw*
1,001 to 3,000 kw*	$660 plus $.50 per kw*
Over 3,000 kw*	$810 plus $.45 per kw*

*Note: Kw load size, for the determination of the Basic Charge, shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Demand Charge:

On-Peak Period Demand (Monday through Friday: 6:00 a.m. to 10:00 p.m.)	Winter** Months	Summer** Months
For each kw of Billing Demand	$1.91	$1.27

**Note:

If the meter reading date is:	The charge is:
January 1 through April 26	Winter
April 27 through October 26	Summer
October 27 through December 31	Winter

(Continued)

A.83-05-052
A.83-07-017

Schedule No. A-36

APPENDIX C
Page 3

LARGE GENERAL SERVICE - Optional
100 KW AND OVER

APPLICABILITY

Applicable to electric service loads which have not registered 500 kw or more, more than once in any consecutive 18-month period. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. A written agreement shall be required for application of this schedule to service furnished for intermittent or highly fluctuating loads. Not applicable to service for use in parallel with, in supplement to, or in standby for customer's electric generation or other energy sources.

TERRITORY

Within the entire territory served in California by the Utility.

MONTHLY BILLING

The Monthly Billing shall be the sum of the Basic, Demand, Energy, and Reactive Power Charges; plus Delivery and Metering Adjustments.

Basic Charge:

If Load Size Is:	The Monthly Basic Charge Is:
100 kw* or less	$215
101 kw* - 300 kw*	$ 58 plus $1.57 per kw*
Over 300 kw*	$184 plus $1.15 per kw*

*Note: Kw load size, for determination of the Basic Charge, shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Demand Charge:

$1.50 per kw for each kw of Billing Demand.

Energy Charge:

Base Rate	ERAM Adjustment	Net Rate
5.099¢	0.00¢	5.099¢ per kwh for all kwh.

Minimum Charge:

Monthly Minimum Charge shall be the Basic Charge plus the Demand Charge for the current month. A higher minimum may be required under contract to cover special conditions.

(Continued)

LARGE GENERAL SERVICE - Optional
(Continued)

BILLING DEMAND
The billing demand shall be the greater of the following:

(a) the maximum measured 15-minute integrated demand in kilowatts occurring during the month,
(b) the diversified resistance welder load computed in accordance with Rule No. 21-2-b, or
(c) 100 kw.

CONTINUING SERVICE
Except as specifically provided otherwise, the rates of this tariff are based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a seasonal customer from minimum monthly charges.

TERM OF CONTRACT
Utility may require customer to sign a written contract which will have a term of not less than five years.

RULES AND REGULATIONS:
Service under this schedule is subject to the General Rules and Regulations contained in the tariff of which this schedule is a part and to those prescribed by regulatory authorities.

A.83-05-052 Schedule No. AT-48 APPENDIX C
A.83-07-017 Page 6

LARGE GENERAL SERVICE - METERED TIME OF USE
500 KW AND OVER

Energy Charge:

Base Rate	ERAM Adjustment	Net Rate	
4.508¢	0.000¢	4.508¢	per kWh for all kWh

Minimum Charge:
The Monthly Minimum Charge shall be the Basic Charge. A higher minimum may be required under contract to cover special conditions.

Reactive Power Charge:
The maximum 15-minute integrated reactive demand in kilovolt-amperes occurring during the month in excess of 40% of the maximum measured 15-minute integrated demand in kilowatts occurring during the month will be billed, in addition to the above charges, at 60¢ per kva of such excess reactive demand.

DELIVERY AND METERING VOLTAGE ADJUSTMENTS
The above monthly charges are applicable without adjustment for voltage when delivery and metering are at utility's standard secondary distribution voltage.

Metering: For so long as metering voltage is at utility's available primary distribution voltage of 11 kv or greater, the above charges will be reduced by 1.5%.

Delivery: For so long as delivery voltage is at utility's available primary distribution voltage of 11 kv or greater, the total of the above charges will be reduced by 15¢ per kw of load size used for the determination of the Basic Charge billed in the month. A High Voltage Charge of $35 per month will be added where such deliveries are metered at the delivery voltage.

When a new delivery or an increase in capacity for an existing delivery is, at request of customer, made by means of utility-owned transformers at a voltage other than a locally standard distribution voltage, the above charges for any month will be increased by 15¢ per kw of load size used for the determination of the Basic Charge billed in the month.

(Continued)

A.83-05-052
A.83-07-017

Schedule No. AT-48

APPENDIX C
Page 5

LARGE GENERAL SERVICE - METERED TIME OF USE
500 KW AND OVER

APPLICABILITY

This schedule is applicable to electric service loads which have ever registered 500 kw or more, more than once in any consecutive 18-month period. This schedule will remain applicable until customer fails to equal or exceed 500 kw for a period of 36 consecutive months. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads will be provided only by special contract for such service.

Partial requirements service for loads of 500 kw and over will be provided only by application of the provisions of Schedule AT-47.

TERRITORY

Within the entire territory served in California by the Utility.

MONTHLY BILLING

The Monthly Billing shall be the sum of the Basic, Demand, Energy, and Reactive Power Charges; plus Metering and Delivery Adjustments.

Basic Charge:

If Load Size is:	The Monthly Basic Charge is:
1,000 kw* or less	$360 plus $.80 per kw*
1,001 to 3,000 kw*	$660 plus $.50 per kw*
Over 3,000 kw*	$810 plus $.45 per kw*

*Note: Kw load size, for the determination of the Basic Charge, shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Demand Charge:

On-Peak Period Demand (Monday through Friday: 6:00 a.m. to 10:00 p.m.)	Winter** Months	Summer** Months
For each kw of Billing Demand	$1.91	$1.27

**Note:

If the meter reading date is:	The charge is:
January 1 through April 26	Winter
April 27 through October 26	Summer
October 27 through December 31	Winter

(Continued)

A.83-05-052
A.83-07-017

Schedule No. AT-48

APPENDIX C
Page 7

LARGE GENERAL SERVICE - METERED TIME OF USE
500 KW AND OVER

Utility retains the right to change its line voltage or classifications thereof at any time, and after reasonable advance notice to any customer affected by such change, such customer then has the option to take service at the new line voltage or to accept service through transformers to be supplied by Utility subject to the voltage adjustments above.

The reductions of charges herein shall not operate to reduce minimum charges for the first 300 kw.

BILLING DEMAND

The Billing Demand shall be the maximum measured 15-minute integrated On-Peak Period demand in kilowatts occurring during the month.

CONTINUING SERVICE

Except as specifically provided otherwise, the rates of this tariff are based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a seasonal customer from minimum monthly charges.

TERM OF CONTRACT

Utility may require customer to sign a written contract which will have a term of not less than five years.

RULES AND REGULATIONS

Service under this schedule is subject to the General Rules and Regulations contained in the tariff of which this schedule is a part and to those prescribed by regulatory authorities.

A.83-05-052
A.83-07-017

Schedule No. AWH-31

APPENDIX C
Page 8

COMMERCIAL WATER HEATING SERVICE

NO NEW SERVICE

APPLICABILITY

Applicable to nonresidential customers for separately metered water heating service taken through one meter and only when used in conjunction with other nonresidential service. This schedule is not applicable to water heating for space heating, stock watering, or winter seasonal purposes or to resale, standby or breakdown service.

TERRITORY

Within the entire territory served in California by the utility.

MONTHLY BILLING

The Monthly Billing shall be the sum of the Basic and Energy Charges.

Basic Charge:	Per Month
For single-phase service	$5.00
For three-phase service	$8.00

Energy Charge:

Base Rate	ERAM Adjustment	Net Rate	
5.582¢	0.000¢	5.582¢	per kwh for all kwh

Minimum Monthly Charge:

The minimum monthly charge shall be the Basic Charge, plus $1.65 per kw for each kw in excess of 10 kw of total capacity of all heating units which may be operated at one time.

SPECIAL CONDITIONS

1. Customer shall install a separate circuit completely enclosed from meter to heaters and associated equipment in metallic conduit or in armored or other cable acceptable to Utility, to which circuit only water heating and associated equipment may be connected. This circuit shall operate at a voltage and phase specified by the Utility. The meter for this circuit shall be located adjacent to the meter of the associated nonresidential service.

2. Except as noted below, the total installed capacity of water heaters served under this schedule shall not exceed the greater of 60 kw or one-fifth of the total installed electric loads of the associated nonresidential electric service.

(Continued)

Pacific Power & Light Company Cal.P.U.C. Sheet No.

Portland, Oregon Cancelling Cal.P.U.C. Sheet No.

A.83-05-052
A.83-07-017

Schedule No. D

APPENDIX C
Page 9

RESIDENTIAL SERVICE

APPLICABILITY

Applicable to single-phase alternating current electric service for residential purposes in single-family dwellings and as specified under Special Conditions of this Schedule, to multiple dwelling units in which each of the single-family dwellings receive service directly from the Utility through separate meters. The rates specified herein will be designated for each service in accordance with the energy uses qualified and elected by the Customer. The Basic Residential Use and Electric Water Heating allowance will apply unless baseline allowances available for electric space heating are qualified and elected.

TERRITORY

Within the entire territory served in California by the Utility.

MONTHLY BILLING

The Monthly Billing shall be the greater of the Minimum Charge or the Energy Charge.

RATES

Energy Charge:

	Per Month					
	Baseline			Non-Baseline		
	Base Rate	ERAM Adjustment	Net Rate	Base Rate	ERAM Adjustment	Net Rate
All kwh per kwh	5.303¢	0.000¢	5.303¢	8.067¢	0.000¢	8.067¢

Minimum Charge:

$2.00

SPECIAL CONDITIONS

1. No motor load shall exceed a total of 7 1/2 horsepower connected at one time.

2. All electric space heaters larger than 1,650 watts rated capacity shall be designed and connected for operation at 240 volts, and each space heating unit having a rated capacity of two (2) kilowatts or larger shall be thermostatically controlled by automatic devices of a type which will cause a minimum of radio interference. Space heaters served under this schedule shall be of types and characteristics approved by the Utility. Individual heaters shall not exceed a capacity of five (5) kilowatts.

(Continued)

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Advice Letter No. Date Filed

Decision No. Effective

Resolution No.

TF6 D-1SCP

A.83-05-052
A.83-07-017

Schedule No. D

APPENDIX C
Page 10

RESIDENTIAL SERVICE
(Continued)

SPECIAL CONDITIONS (Continued)

3. Service under this schedule may be furnished to multiple family dwellings such as apartments, complexes, condominiums and mobile home parks in which the single-family dwellings receive service directly from the Utility through separate meters.

4. Baseline rates are applicable only to separately metered residential usage. The Utility may require the Customer to complete and file with it an appropriate Declaration of Baseline Eligibility.

5. The following quantities of electricity are to be billed at the rates for baseline usage:

	Kwhr Baseline Allowance Per Meter Per Month: Basic Use and Electric Water Heating	Permanently Installed Electric Space Heating
A. Del Norte County:		
October 1 through May 31	495	1,086
June 1 through September 30	420	550
B. All other territory served by the Utility:		
November 1 through April 30	520	1,265
May 1 through October 31	420	550

Energy used in excess of the baseline allowance will be billed at the nonbaseline rate, continuing from the quantity reached by the baseline allowances.

6. Electric water heating is defined as permanently installed and wired electrical devices which provide the principal source of heat for hot water.

7. Permanently installed electric space heating is defined as any of the following: permanently installed and wired resistive elements which provide the principal source of heat, heat pumps, or any permanently installed water or steam heating using electric heating devices as the principal source of heat. Space heating baseline allowance is applicable only for the period of October 1 through May 31 in Del Norte County and November 1 through April 30 in all other territory served by the Utility.

8. The baseline allowances for space heating in Del Norte County will be prorated in the October and June billing periods based on the ratio of the number of days prior to June 1 and subsequent to September 30.

(Continued)

A.83-05-052
A.83-07-017

Schedule No. D

APPENDIX C
Page 11

RESIDENTIAL SERVICE
(Continued)

SPECIAL CONDITIONS (Continued)

respectively, to the total number of days in the billing period. The baseline allowances for space heating in all other territory served by the Utility will be prorated in the May and November billing periods based on the ratio of the number of days prior to May 1 and subsequent to October 31, respectively, to the total number of days in the billing period.

9. STANDARD MEDICAL QUANTITIES FOR RESIDENTIAL CUSTOMERS: A residential customer who certifies in writing that regular use of a medical life-support device, as defined below is essential to maintain the life of a full-time resident of the household, that a full-time resident of the household is a paraplegic, hemiplegic, or quadriplegic person, and/or that a full-time resident of the household is a multiple sclerosis patient, is eligible for a standard monthly medical quantity in addition to the standard monthly non-medical baseline quantity. The amount of the additional quantity shall be 500 kWh.

If the customer believes the life-support device upon which a full-time resident of the customer's household depends to sustain life requires more than 500 kWh to operate, the customer may apply for a higher quantity than that provided in this Rule. Upon receipt of the application, the utility shall make a determination based on the device's nameplate ratings and operating hours, of what additional number of kWh per month are required to operate the device. The additional quantity provided in this special condition shall be increased to the number kWh per month and rounded to the next higher 500 kWh.

The utility may require certification by a doctor of medicine or osteopathy licensed to practice medicine in the State of California that a medical need exists and that a particular device is necessary to sustain the resident's life.

10. LIFE SUPPORT DEVICE: For the purpose of determining baseline quantities under the provisions of a rate schedule applicable to residential uses, a life-support device is any medical device requiring utility-supplied energy for its operation that is regularly required to maintain the life of a person residing in a residential unit. The term includes respirators, iron lungs, hemodialysis machines, suction machines, electric nerve stimulators, pressure pads and pumps, aerosol tents, electrostatic and ultrasonic nebulizers, compressors, IPPB machines and motorized wheelchairs. It also includes additional space heat for paraplegic, hemiplegic and quadriplegic persons and additional space heat and air conditioning for multiple sclerosis patients.

CONTINUING SERVICE

Except as specifically provided otherwise, the rates of this tariff are based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a customer from minimum monthly charges.

A.83-05-052
A.83-07-017

APPENDIX C
Page 12

Schedule No. DS-8

MULTI-FAMILY RESIDENTIAL SERVICE - SUBMETERED

APPLICABILITY

Applicable to single-phase alternative current electric service for residential purposes in multi-family living units which receive electric service through a master meter on a single premises with all individual family units submetered and billed as specified under Special Conditions of this Schedule. The rates specified herein will be designated for each service in accordance with the energy uses qualified and elected by the Customer. The Basic Residential Use and Electric Water Heating baseline allowance will apply unless baseline allowances available for electric space heating are qualified and elected.

TERRITORY

Within the entire territory served in California by the Utility.

MONTHLY BILLING

The Monthly Billing shall be calculated in accordance with the applicable Residential Service Schedule No. D, less 10% discount on the Minimum Charge* and Baseline rates.

*Note: The Minimum Charge is applied per DS-8 Account.

MINIMUM CHARGE

The Minimum Charge shall be calculated in accordance with the applic-able Residential Service Schedule No. D, less 10% discount. A higher minimum may be required under contract to cover special conditions.

SPECIAL CONDITIONS

1. No motor load shall exceed a total of 7 1/2 horsepower connected at one time.

2. All electric space heaters larger than 1,650 watts rated capacity shall be designed and connected for operation at 240 volts, and each space heating unit having a rated capacity of two (2) kilowatts or larger shall be thermostatically controlled by automatic devices of a type which will cause a minimum of radio interference. Space heaters served under this schedule shall be of types and characteristics approved by the Utility. Individual heaters shall not exceed a capacity of five (5) kilowatts.

3. Service under this schedule may be furnished to multiple dwelling units such as apartment houses, court groups, mobile home parks and related electric facilities which receive service through a master meter on a single premises with individual family units submetered. When so supplied, the number of kilowatt-hours in each block of the rate shall be multiplied by the number of submeterd single-family dwelling units or apartments.

(Continued)

A.83-05-052
A.83-07-017

Schedule No. DS-8

APPENDIX C
Page 13

MULTI-FAMILY RESIDENTIAL SERVICE - SUBMETERED
(Continued)

SPECIAL CONDITIONS (Continued)

served. In determination of the multiplier, it is the responsibility of the Customer to advise the Utility within 15 days following any change in the number of residential dwelling units and mobile homes wired for service.

4. Submetered dwelling units receiving service from accounts master metered and billed hereunder shall in turn be billed at the rates of Schedule No. D of this tariff.

5. Miscellaneous electrical loads such as general lighting, laundry rooms, general maintenance and other similar usage incidental to the operation of the premises as a multi-family accommodation will be considered as domestic usage.

6. Electric energy for nondomestic enterprises such as rooming houses, boarding houses, dormitories, rest homes, military barracks, stores, restaurants, service stations and similar establishments will be separately metered and billed under the applicable general service schedules.

7. Baseline rates are applicable only to separately metered residential usage. The Utility may require the Customer to complete and file with it an appropriate Declaration of Baseline Eligibility.

8. The following quantities of electricity are to be billed at the rates for baseline usage:

	Monthly Kwhr Allowance Per Meter Per Month	
	Basic Use and Electric Water Heating	Permanently Installed Electric Space Heating
A. Del Norte County:		
October 1 through May 31	495	1,086
June 1 through September 30	420	550
B. All other territory served by the Utility:		
November 1 through April 30	520	1,265
May 1 though October 31	420	550

Energy used in excess of the baseline allowance will be billed at the nonbaseline rate, continuing from the quantity reached by the baseline allowances.

(Continued)

MULTI-FAMILY RESIDENTIAL SERVICE - SUBMETERED
(Continued)

SPECIAL CONDITIONS (Continued)

9. Electric water heating is defined as permanently installed and wired electrical devices which provide the principal source of heat for hot water.

10. Permanently installed electric space heating is defined as any of the following: Permanently installed and wired resistive elements which provide the principal source of heat, heat pumps, or any permanently installed water or steam heating using electric heating devices as the principal source of heat. Space heating baseline allowance is applicable only for the period of October 1 through May 31 in Del Norte County and November 1 through April 30 in all other territory served by the Utility.

11. The baseline allowances for space heating in Del Norte County will be prorated in the October and June billing periods based on the ratio of the number of days prior to June 1 and subsequent to September 30, respectively, to the total number of days in the billing period. The baseline allowances for space heating in all other territory served by the Utility will be prorated in the May and November billing periods based on the ratio of the number of days prior to May 1 and subsequent to October 31, respectively, to the total number of days in the billing period.

12. Three phase load will be supplied service under this schedule for multi-family residential customers who were supplied three phase service on a general service schedule on January 1, 1977.

13. STANDARD MEDICAL QUANTITIES FOR RESIDENTIAL CUSTOMERS: A residential customer who certifies in writing that regular use of a medical life-support device, as defined below is essential to maintain the life of a full-time resident of the household, that a full-time resident of the household is a paraplegic, hemiplegic, or quadriplegic person, and/or that a full-time resident of the household is a multiple sclerosis patient, is eligible for a standard monthly medical quantity in addition to the standard monthly non-medical baseline quantity. The amount of the additional quantity shall be 500 kWh.

If the customer believes the life-support device upon which a full-time resident of the customer's household depends to sustain life requires more than 500 kWh to operate, the customer may apply for a higher quantity than that provided in this Rule. Upon receipt of the application, the utility shall make a determination based on the device's nameplate ratings and operating hours, of what additional number of KWh per month are required to operate the device. The additional quantity provided in this special condition shall be increased to the number KWh per month and rounded to the next higher 500 kWh.

The utility may require certification by a doctor of medicine or osteopathy licensed to practice medicine in the State of California that a medical need exists and that a particular device is necessary to sustain the resident's life.

(Continued)

A.83-05-052
A.83-07-017

Schedule No. DS-8

APPENDIX C
Page 15

MULTI-FAMILY RESIDENTIAL SERVICE - SUBMETERED
(Continued)

14. LIFE SUPPORT DEVICE: For the purpose of determining baseline quantities under the provisions of a rate schedule applicable to residential uses, a life-support device is any medical device requiring utility-supplied energy for its operation that is regularly required to maintain the life of a person residing in a residential unit. The term includes respirators, iron lungs, hemodialysis machines, suction machines, electric nerve stimulators, pressure pads and pumps, aerosol tents, electrostatic and ultrasonic nebulizers, compressors, IPPB machines and motorized wheelchairs. It also includes additional space heat for paraplegic, hemiplegic and quadriplegic persons and additional space heat and air conditioning for multiple sclerosis patients.

Issued by

Advice Letter No. — NAME — Date Filed

Decision No. — TITLE — Effective

Resolution No.

A.83-05-052
A.83-07-017

Schedule No. DM-9

APPENDIX C
Page 16

MULTI-FAMILY RESIDENTIAL SERVICE - MASTER METERED

APPLICABILITY

Applicable to single-phase alternating current electric service for residential purposes in multi-family living units which receive electric service through one meter on a single premises, as specified under Special Conditions of this Schedule. The rates specified herein will be designated for each service in accordance with the energy uses qualified and elected by the Customer. The Basic Residential Use baseline allowance will apply unless baseline allowances available for electric space heating are qualified and elected.

TERRITORY

Within the entire territory served in California by the Utility.

MONTHLY BILLING

The Monthly Billing shall be calculated in accordance with the applicable Residential Service Schedule No. D.

*Note: The Minimum Charge is applied per unit.

MINIMUM CHARGE

The Minimum Charge shall be calculated in accordance with the applicable Residential Service Schedule No. D. A higher minimum may be required under contract to cover special conditions.

SPECIAL CONDITIONS

1. No motor load shall exceed a total of 7 1/2 horsepower connected at one time.

2. All electric space heaters larger than 1,650 watts rated capacity shall be designed and connected for operation at 240 volts, and each space heating unit having a rated capacity of two (2) kilowatts or larger shall be thermostatically controlled by automatic devices of a type which will cause a minimum of radio interference. Space heaters served under this schedule shall be of types and characteristics approved by the Utility. Individual heaters shall not exceed a capacity of five (5) kilowatts.

3. Service under this schedule may be furnished to multiple dwelling units, such as apartment houses, court groups, mobile home parks and related electric facilities through a single meter. Where so supplied, the number of kilowatt-hours in each block of the rate shall be multiplied by the number of single-family dwelling units or apartment served. In determination of the multiplier, it is the responsibility of the Customer to advise the Utility within 15 days following any change in the number of residential dwelling units and mobile homes wired for service.

4. Miscellaneous electrical loads such as general lighting, laundry rooms, general maintenance and other similar usage incidental to the operation of the premises as a multi-family accommodation will be considered as domestic usage.

(Continued)

A.83-05-052
A.83-07-017

Schedule No. DM-9

MULTI-FAMILY RESIDENTIAL SERVICE - MASTER METERED
(Continued)

SPECIAL CONDITIONS (Continued)

5. Electric energy for nondomestic enterprises such as rooming houses, boarding houses, dormitories, rest homes, military barracks, stores, restaurants, service stations and similar establishments will be separately metered and billed under the applicable general service schedules.

6. Baseline rates are applicable only to separately metered residential usage. The Utility may require the Customer to complete and file with it an appropriate Declaration of Baseline Eligibility.

7. The following quantities of electricity are to be billed at the rates for baseline usage:

	Monthly Kwhr Allowance Per Unit Per Month	
	Basic Use and Electric Water Heating	Permanently Installed Electric Space Heating
A. Del Norte County:		
October 1 through May 31	396	652
June 1 thourh September 30	336	330
B. All other territory served by the Utility:		
November 1 through April 30	416	759
May 1 through October 31	336	330

*Any submetered unit will receive the allowance for individually metered units as shown on Schedule No. DS-6.

Energy used in excess of the baseline allowance will be billed at the nonbaseline rate, continuing from the quantity reached by the baseline allowances.

8. Electric water heating is defined as permanently installed and wired electrical devices which provide the principal source of heat for hot water.

9. Permanently installed electric space heating is defined as any of the following: Permanently installed and wired resistive elements which provide the principal source of heat, heat pumps, or any permanently installed water or steam heating using electric heating devices as the principal source of heat. Space heating baseline allowance is applicable only for the period of October 1 through May 31 in Del Norte County and November 1 through April 30 in all other territory served by the Utility.

(Continued)

A.83-05-052
A.83-07-017

Schedule No. DM-9

APPENDIX C
Page 18

MULTI-FAMILY RESIDENTIAL SERVICE - MASTER METERED
(Continued)

SPECIAL CONDITIONS (Continued)

10. The baseline allowances for space heating in Del Norte County will be prorated in the October and June billing periods based on the ratio of the number of days prior to June 1 and subsequent to September 30, respectively, to the total number of days in the billing period. The baseline allowances for space heating in all other territory served by the Utility will be prorated in the May and November billing periods based on the ratio of the number of days prior to May 1 and subsequent to October 31, respectively, to the total number of days in the billing period.

11. Three phase load will be supplied service under this schedule for multi-family residential customers who were supplied three phase service on a general service schedule on January 1, 1977.

12. STANDARD MEDICAL QUANTITIES FOR RESIDENTIAL CUSTOMERS: A residential customer who certifies in writing that regular use of a medical life-support device, as defined below is essential to maintain the life of a full-time resident of the household, that a full-time resident of the household is a paraplegic, hemiplegic, or quadriplegic person, and/or that a full-time resident of the household is a multiple sclerosis patient, is eligible for a standard monthly medical quantity in addition to the standard monthly non-medical baseline quantity. The amount of the additional quantity shall be 500 kWh.

If the customer believes the life-support device upon which a full-time resident of the customer's household depends to sustain life requires more than 500 kWh to operate, the customer may apply for a higher quantity than that provided in this Rule. Upon receipt of the application, the utility shall make a determination based on the device's nameplate ratings and operating hours, of what additional number of kWh per month are required to operate the device. The additional quantity provided in this special condition shall be increase to the number kWh per month and rounded to the next higher 500 kWh.

The utility may require certification by a doctor of medicine or osteopathy licensed to practice medicine in the State of California that a medical need exists and that a particular device is necessary to sustain the resident's life.

13. LIFE SUPPORT DEVICE: For the purpose of determining baseline quantities under the provisions of a rate schedule applicable to residential uses, a life-support device is any medical device requiring utility-supplied energy for its operation that is regularly required to maintain the life of a person residing in a residential unit. The term includes respirators, iron lungs, hemodialysis machines, suction machines, electric nerve stimulators, pressure pads and pumps, aerosol tents, electrostatic and ultrasonic nebulizers, compressors, IPPB machines and motorized wheelchairs. It also includes additional space heat for paraplegic, hemiplegic and quadriplegic persons and additional space heat and air conditioning for multiple sclerosis patients.

Pacific Power & Light Company
Portland, Oregon

Cal.P.U.C. Sheet No.
Cancelling Cal.P.U.C. Sheet No.

A.83-05-052
A.83-07-017

Schedule No. LS-51

APPENDIX C
Page 19

HIGH PRESSURE SODIUM VAPOR
STREET AND HIGHWAY LIGHTING SERVICE
UTILITY-OWNED SYSTEM

APPLICABILITY

To service furnished, by means of Utility-owned installations, for the dusk-to-dawn illumination of public streets, highways, alleys and parks by means of high-pressure sodium-vapor street lights installed on distribution-type wood poles and served by overhead circuits. The type and kind of fixtures and supports will be in accordance with Utility's specifications. Service includes installation, maintenance, energy, lamp and glassware renewals.

AVAILABLE

Within the entire territory in California served by Utility.

MONTHLY BILLING

Nominal Lumen Rating	Rate per Lamp		
	Base Rate	ERAM Adjustment	Net Rate
5,800	$ 7.32	$0.00	$ 7.32
9,500	8.12	0.00	8.12
22,000	13.59	0.00	13.59
50,000	26.00	0.00	26.00

SPECIAL PROVISIONS

1. Utility will replace individually burned out or broken lamps as soon as practicable during regular business hours after notification by the customer.

2. Utility may require customer participation in the cost of installing circuit to render street lighting service when the length of such circuit from a source of suitable voltage on Utility's system to the point of connection with the proposed street light or street lighting system is in excess of 300 feet.

3. Utility may not be required to furnish service hereunder to other than municipal customers.

4. The customer may request temporary suspension of power for lighting by written notice. During such periods, the monthly rate will be reduced by Utility's estimated average monthly relamping and energy costs for the luminaire. Utility will not be required to reestablish such service under this rate schedule if service has been permanently discontinued by the customer.

5. Utility may not be required to install or maintain street lights employing fixtures or supports or at locations unacceptable to Utility.

TERM OF CONTRACT:

Not less than one year.

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A.83-05-052
A.83-07-017

Schedule No. LS-52

APPENDIX C
Page 20

SPECIAL STREET AND HIGHWAY LIGHTING SERVICE

UTILITY-OWNED SYSTEM

APPLICABILITY

To service furnished, by means of Utility-owned installations, for the dusk-to-dawn illumination of public streets, highways, alleys and parks under conditions and for street lights of sizes and types not specified on other schedules of this tariff. Utility may not be required to furnish service hereunder to other than municipal customers.

TERRITORY

Within the entire territory in California served by Utility.

MONTHLY BILLING

A flat rate equal to one-twelfth of Utility's estimated annual cost for operation, maintenance, fixed charges and depreciation applicable to the street lighting system, including energy costs as follows:

For dusk-to-dawn operation at the rate of:

Base Rate	ERAM Adjustment	Net Rate	
7.678¢	0.00¢	7.678¢	per kwhr

TERM OF CONTRACT

Not less than five years for service from an overhead, or ten years from an underground, system by written contract.

CONVERSION OF LIGHTS

Incandescent or mercury-vapor lights used to furnish service hereunder are subject to conversion to high-pressure sodium-vapor lights by not less than sixty (60) days' written notice given by Utility to the customer. Contingent on the availability of adequate manpower and materials, service hereunder will be converted to high-pressure, sodium-vapor street-lighting service, in accordance with the following schedule:

All incandescent; 21,000-lumen and 55,000-lumen street lights by July 20, 1982.

All 7,000-lumen mercury-vapor street lights by July 20, 1985.

(Continued)

A.83-05-052
A.83-07-017

Schedule No. LS-53

APPENDIX C
Page 21

SPECIAL STREET AND HIGHWAY LIGHTING SERVICE

CUSTOMER-OWNED SYSTEM

APPLICABILITY

To service furnished by means of customer-owned installations, for the dusk-to-dawn illumination of public streets, highways, alleys and parks under conditions and for street lights of sizes and types not specified on other schedules of this tariff. Utility may not be required to furnish service hereunder to other than municipal customers.

TERRITORY

Within the entire territory in California served by Utility.

MONTHLY BILLING

a) Where Utility operates and maintains the system, a flat rate equal to one-twelfth the estimated annual cost for energy, operation and maintenance with energy at the rate of:

Base Rate	ERAM Adjustment	Net Rate
7.678¢	0.00¢	7.678¢ per kwhr

b) Where the customer operates and maintains the system, a flat rate equal to one-twelfth the estimated annual energy cost at the rate of:

Base Rate	ERAM Adjustment	Net Rate
7.678¢	0.00¢	7.678¢ per kwhr

TERM OF CONTRACT

Not less than five years under option (a) or one year under option (b).

SPECIAL CONDITIONS

1. Under option (a), Utility will replace individually burned out or broken lamps as soon as practicable during normal business hours after notification by customer.
2. Utility may not be required to maintain street lights employing fixtures or at locations unacceptable to Utility.
3. In the event the customer installs a series system, the customer shall also provide, install and maintain the necessary series transformers.

A.83-05-052
A.83-07-017

Schedule No. LS-57

STREET AND HIGHWAY LIGHTING SERVICE
UTILITY-OWNED SYSTEM
NO NEW SERVICE

APPLICABILITY

Applicable to lighting for public streets, roads, highways and other public outdoor lighting service.

TERRITORY

With the entire territory in California served by the Utility.

I. MONTHLY BILLING FOR LIGHTS OWNED, OPERATED AND MAINTAINED BY UTILITY AND INSTALLED PRIOR TO APRIL 4, 1977

A. Overhead System

Street lights on distribution type wood poles:

Incandescent Lamps

Nominal Lumen Rating	600	1000	2500	4000	6000
Rate per Lamp	$3.74	$4.83	$8.27	$12.09	$15.92

Mercury Vapor Lamps

Nominal Lumen Rating	7000	21000
Rate per Lamp - horizontal	$ 9.39	$17.99
Rate per Lamp - vertical	$ 8.85	$17.64

Street lights on metal poles:

Mercury Vapor Lamps

Nominal Lumen Rating	7000	21000
Rate per Lamp		
Horizontal	$11.60	--
Horizontal		$20.73

B. Underground System

Street lights on metal poles:

Mercury Vapor Lamps

Nominal Lumen Rating	7000	21000
Rate per Lamp		
Horizontal	--	$24.25
Vertical	--	$22.30

(Continued)

A.83-05-052
A.83-07-017

Schedule No. LS-57

APPENDIX C
Page 23

STREET AND HIGHWAY LIGHTING SERVICE
UTILITY-OWNED SYSTEM
NO NEW SERVICE
(Continued)

II. MONTHLY BILLING FOR OVERHEAD SYSTEM, MERCURY-VAPOR STREET LIGHTS OWNED, OPERATED AND MAINTAINED BY UTILITY AND INSTALLED AFTER APRIL 4, 1977

Street lights on distribution type wood poles:

Nominal Lumen Rating	7000	21000
Rate per Lamp	$10.12	$18.58

ADJUSTMENTS

The above rates include an adjustment as specified in Part B of the Preliminary Statement, as follows:

	Per KWH
Electric Revenue Adjustment	$0.00

CONVERSION OF UTILITY-OWNED LIGHTS

Utility-owned incandescent or mercury-vapor lights used to furnish service hereunder are subject to conversion to high-pressure sodium vapor lights by not less than sixty (60) days' written notice given by Utility to the customer. Contingent on the availability of adequate manpower and materials, service hereunder will be converted to high-pressure, sodium-vapor street-lighting service, in accordance with the following schedule:

All incandescent; 21,000-lumen and 55,000-lumen street lights by July 20, 1982.

All 7,000-lumen mercury-vapor street lights by July 20, 1985.

SPECIAL CONDITIONS

1. The rates are based on dusk-to-dawn burning.
2. The Utility will replace individually burned out or broken lamps as soon as practicable during normal business hours after notification by the customer.
3. The Utility may require special five year contracts to cover unusual operating and maintenance conditions due to a minimum number of lamps in service, the distance from service centers or undue hazard to equipment.

A.83-05-052
A.83-07-017

Schedule No. LS-58

APPENDIX C
Page 24

STREET AND HIGHWAY LIGHTING SERVICE
CUSTOMER-OWNED SYSTEM
NO NEW SERVICE

APPLICABILITY

Applicable to lighting for public streets, roads, highways and other public outdoor lighting service.

TERRITORY

Within the entire territory in California served by the Utility.

MONTHLY BILLING PER LIGHT

Class A: Customer owns, installs, operates and maintains entire required installation. Utility delivers energy at one point only as near as practical to the customer's installation.

Class B: Customer owns and installs entire required installation. Utility delivers energy at one point only as near as practical to the customer's installation. Utility operates and maintains entire required installation except for the painting, repair and replacement of poles and circuits.

NOMINAL LUMEN RATING	CLASS A			CLASS B		
INCANDESCENT	Base Rate	ERAM Adjustment	Net Rate	Base Rate	ERAM Adjustment	Net Rate
1,000	$ 3.31	$0.00	$ 3.31	$ 4.53	$0.00	$ 4.53
2,500	6.54	0.00	6.54	7.81	0.00	7.81
4,000	10.67	0.00	10.67	11.99	0.00	11.99
6,000	14.61	0.00	14.61	15.98	0.00	15.98
MERCURY VAPOR	Base Rate	ERAM Adjustment	Net Rate	Base Rate	ERAM Adjustment	Net Rate
7,000	$ 6.81	$0.00	$ 6.81	$ 7.55	$0.00	$ 7.55
21,000	15.41	0.00	15.41	16.20	0.00	16.20
55,000	36.90	0.00	36.90	37.97	0.00	37.97
FLUORESCENT	Base Rate	ERAM Adjustment	Net Rate	Base Rate	ERAM Adjustment	Net Rate
21,400	$14.61	$0.00	$14.61	$16.56	$0.00	$16.56

(Continued)

AIRWAY AND ATHLETIC FIELD LIGHTING SERVICE

APPLICABILITY

Applicable to service for airway beacons, the lighting of airfields, the lighting of publicly owned and operated outdoor athletic fields, and for incidental use therewith.

TERRITORY

Within the entire territory served in California by the Utility.

MONTHLY BILLING

The Monthly Billing shall be the sum of the Basic and Energy Charges.

Basic Charge:	Per Month
For single-phase service	$5.00
For three-phase service	$8.00

Energy Charge:

Base Rate	ERAM Adjustment	Net Rate	
9.346¢	0.00¢	9.346¢	per kwh for all kwh

Minimum Charge:

The minimum monthly charge shall be the Basic Charge, but in no event will the annual billing be less than $1.20 per kw or $1.20 per horsepower of connected load.

SPECIAL CONDITIONS

1. Delivery to be made at one central point. The customer shall install and maintain the distribution system.

2. Extensions to supply service under this schedule will be made in accordance with the established rule of the Utility governing extensions.

CONTINUING SERVICE

Except as specifically provided otherwise, the rates of this tariff are based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a seasonal customer from minimum monthly charges.

A.83-05-052
A.83-07-017

Schedule No. OL-15

APPENDIX C
Page 25

OUTDOOR AREA LIGHTING SERVICE
NO NEW SERVICE

APPLICABILITY

To all customers for lighting outdoor areas other than public streets, roads and highways. Lighting service will be furnished from dusk to dawn by Utility-owned luminaires which may be served by secondary voltage circuits from Utility's existing overhead distribution system. Luminaires will be mounted on Utility's wood poles and served in accordance with Utility's specifications as to equipment and installation.

TERRITORY

Within the entire territory served in California by the Utility.

MONTHLY BILLING

Type of Luminaire	Nominal Lamp Rating		Rate Per Luminaire: Base Rate	ERAM Adjustment	Net Rate
Mercury Vapor	* 7,000	lumens	$11.22	$0.00	$11.22
" "	*21,000	"	22.46	0.00	22.46
" "	*55,000	"	48.78	0.00	48.78
High Pressure Sodium	5,800	"	$12.08	$0.00	$12.08
" " "	22,000	"	19.39	0.00	19.39
" " "	50,000	"	32.57	0.00	32.57

*No new installations

Pole Charge:

Above rates include installation of one wood pole, if required. A monthly charge of $1.00 per pole will be made for each additional pole required in excess of the number of luminaires installed.

SPECIAL CONDITIONS

1. A written contract for an initial term of three years will be required by Utility.
2. Maintenance will be performed during regular working hours as soon as practicable after customer has notified Utility of service failure.
3. The utility's dusk-to-dawn service is based on a burning schedule of approximately 4,000 hours per year.

A.83-05-052
A.83-07-017

Schedule No. PA-20

APPENDIX C
Page 27

AGRICULTURAL PUMPING SERVICE

APPLICABILITY

This schedule is applicable to customers desiring seasonal service for irrigation and soil drainage pumping installations only. Service furnished under this schedule will be metered and billed separately at each point of delivery.

TERRITORY

In all territory served by the Utility in the State of California.

MONTHLY CHARGE

The monthly billing shall be the sum of the applicable Demand, Energy Charges and Reactive Power Charges. The Annual Charge will be included in the bill for the November billing month.

Meter Readings from March 26 through November 28:

Energy Charge:

Base Rate	ERAM Adjustment	Net Rate	
4.890¢	0.00¢	4.890¢	per kwh for the first 14,000 kwh
4.694¢	0.00¢	4.694¢	per kwh for all additional kwh

Meter Readings from November 29 through March 25:

Demand Charge:

$1.21 per kw of monthly Billing Demand

Energy Charge

Base Rate	ERAM Adjustment	Net Rate	
7.090¢	0.00¢	7.090¢	per kwh for the first 100 kwh monthly per kw of monthly Billing Demand
5.601¢	0.00¢	5.601¢	per kwh for all additional kwh

ANNUAL CHARGE (collected in November Billing Period)

If Load Size is:	Annual Charge is:
Single-phase service, any size:	$10 per kw* but not less than a Basic Charge of $36

*Note: Kw load size, for determination of the Annual Charge, shall be the average of the two greatest non-zero monthly Billing Demands established during the 12-month period which includes and ends with the current billing month.

(Continued)

A-5a

LEONARD M. GRIMES, JR., President, VICTOR CALVO, Commissioner, DONALD VIAL, Commissioner, Concurring:

We concur in today's decision granting PP&L rate relief. However, we cannot agree with the manner in which today's decision defers consideration of whether or not PP&L's rate of return should be adjusted to reflect our prior denial of amortization of nuclear abandonment losses in D.83-11-012, as modified by D.84-05-097. Today's decision has left this issue of a risk premium open for further review pending disposition of PP&L's Petition for Writ of Review with the California Supreme Court and of its application for Rehearing of D.84-05-097.[1/] In order to prevent any misunderstanding in future proceedings, we would like to go on record to express our views on the propriety of imputing risk factors into utilities' return on equity and, in particular, any risk factor related to so-called "regulatory" risk.

First, we must recognize that D.84-05-097 completely changed the basis for our original denial of cost recovery as discussed in D.83-11-012. While the rationale underlying D.83-11-012 could have been interpreted by some as introducing a change in the policy basis for denial of amortization losses, and thus possibly increasing future risk factors, D.84-05-012 rendered that possibility moot by reaffirming prior longstanding policies. Seen in this light, the denial of amortization losses in D.84-05-097 introduces no new risk factors in the future operation of PP&L.

Second, it is our policy to fairly compensate utility shareholders for the risks we impose on utility operations and their ability to earn a fair rate of return <u>in the future</u>. This risk is incorporated in the rate of return analysis in the general rate case, which looks at shareholder expectations of the company's total future risks. In certain circumstances, involving change in existing

1/ It should be noted that today we separately denied PP&L's Petition for Rehearing of D.84-05-097, as referred to above.

regulatory policy, we have also given consideration to possible additional risks imposed on affected utilities. For example, when we adopted a target capacity factor for SONGS 2 in D.83-09-007, we considered this new policy's effect on investor risk and the utilities' rate of return. Such consideration is appropriate when we look at future risks and future rate of returns.

However, in our view, it is not appropriate for the Commission to adjust a utility's rate of return for so-called "regulatory risk." Regulatory risk relates to the make up of a particular commission and the type of policies it might pursue. We do not explicitly recognize in the rate or return on equity, the risk of what this commission may do in arriving at policies or decisions. The proper consideration of risk relates to the actual policy or the decision itself as it may affect the risk to shareholders of operating the utility prospectively. Others may judge commissions for regulatory risk but we do not recognize such a risk factor in determining the return on equity for a particular utility.

In the instant case of PP&L and our decision to deny amortization of nuclear abandonment losses in D.84-05-097, it is clear that we relied on our traditional policy of holding shareholders liable for expenses unreasonably incurred. Our action did not impose a new risk on PP&L. It was simply a dissallowance for substandard past management performance. In our view it would be incongruous to offset such a disallowance for management's past inadequacies by now rewarding PP&L with a premium on its equity return. From the regulatory perspective such a reward would render the disallowance meaningless.

Donald Vial
DONALD VIAL, Commissioner

Leonard M. Grimes
LEONARD M. GRIMES, JR., President

Victor Calvo
VICTOR CALVO, Commissioner

July 18, 1984
San Francisco, California

A.83-05-52, A.83-07-17
D.84-07-150

PRISCILLA C. GREW, Commissioner, dissenting.

I dissent, because I cannot support, as the majority does, the granting of a $6.7 million rate increase in response to an application for an increase of only $6.0 million.

This decision addresses two applications of Pacific Power and Light Company (Pacific): A.83-05-52, filed May 25, 1983, in which Pacific requested a general rate increase of $6,034,000, and A.83-07-17, filed July 8, 1983, in which Pacific requested the establishment of an ERAM with a rate increase of $4,913,000. In ruling today on the latter application, the majority allowed Pacific to establish an ERAM but correctly rejected the entire requested rate increase of $4,913,000 because granting the increase would have been retroactive ratemaking. The Commission went on, however, to grant a rate increase of $6,737,000 in response to the company's general rate increase application, which exceeds Pacific's request in that application.

The Commission should not grant an increase greater than a utility's request. At no time in my service as a Commissioner do I recall the Commission doing this. When the Commission has confronted this issue in the past, it concluded that "applicants may not properly be authorized to increase any rate above that proposed ... in their application and in the notices to ... interested parties," even when such an increase was clearly justified. (Southern California Carloading Tariff Bureau, 46 CRC 831, 836 (1946).) When circumstances change following initial applications, utilities have adequate opportunity to amend their applications and increase their requests under Rules 8 and 23 (k) of the Commission's Rules of Practice and Procedure. I find it disturbing that the majority takes the extraordinary step of granting a general rate increase that exceeds the utility's request without considering or discussing the policy or legal implications of its action.

I do not think that Pacific's customers received meaningful and adequate notice of the increase granted today. The majority avoids this notice objection by simply arguing that the increase requested in the general rate case can be added to the separate increase request in the ERAM application. Using this argument, the majority concludes that Pacific's customers had notice that a cumulative increase of $10,947,000 had been requested. The actual notice for the ERAM was exhibited at our meeting to demonstrate that the notice to customers covered the extra $700,000 granted above the general rate case request.

The majority's reasoning is flawed and the implications of its conclusions are extremely disturbing. The majority argument ignores the fact that the entire rate increase associated with the ERAM application was denied. All that then remains for the Commission's action is the $6,034,000 request of A.83-05-52. These two cases were consolidated for convenience. Pacific's attorneys and nearly all its witnesses are located in Portland, Oregon, 650 miles from our headquarters in San Francisco, and most of the interested parties reside in Pacific's California service areas 350 miles to the north. Consolidating these cases saved considerable travel time and expense, but should not be interpreted somehow to expand the amount requested in the general rate case. If these two matters had not been consolidated, would the majority justify its action by saying that the increase fell somewhere within the total amount of all of Pacific's pending rate increase applications? The majority asserts that notice is cumulative. Under this assertion, are customers to expect that the increase granted in any one application may exceed that particular request as long as it is less than the cumulative requests of all pending applications from that utility?

Pacific's ratepayers had a reasonable expectation, based on the notice served on them, that the general rate case increase would not be more than the $6,034,000 requested by Pacific, and that the ERAM decision would not exceed $4.9 million. According to the majority's reasoning, customers should have assumed that either the general rate case or the ERAM award could be anything up to $10,947,000 as long as the combined total did not exceed $10,947,000. In my view, such confusion for the public and parties in the case resulting from today's decision is reason enough to oppose the majority's action. Customers are entitled to notices that provide the elementary information concerning the limits of a potential rate increase.

The majority's decision also undermines the Commission's recent efforts to encourage public participation in our proceedings. The Commission has developed a program to provide financial assistance to individual members of the public and representatives of organizations who participate in our proceedings and who substantially contribute to the Commission's determinations. We have appointed a Public Advisor to explain our procedures to public participants. And yet with today's action the majority erodes the credibility of notice, the first critical step in public participation. From today on, is the public to understand that a notice indicates only that a rate increase has been proposed and that the amount and elements of that proposal are subject to expansion without notice by consolidation with other pending utility requests?

At the heart of my objection to the majority's action is the importance of adequately informing utility customers of requests being considered by the Commission. The majority seems to believe that notice is adequate if it meets the formal minimum requirements of Public Utilities Code Section 454 and Rule 24 of the Commission's Rules of Practice and Procedure. Further, the majority reasons, once these formalities have been completed, the notice remains adequate despite changes in the nature or amount of the utility's request. I cannot agree. The purpose of notice is to inform all affected by a proposed increase - customers, governmental entities and officers, and other interested parties (see Rule 24) - of the amount and the elements of the proposed increase. That is why we require notice that the utility will furnish a copy of its application and supporting exhibits on written request and why we require a copy of these documents to be available for public inspection at the utility's offices and at the Commission's offices.

What is the point of this detailed notice requirement if the Commission may go beyond the requested increase of an application and act on items that have been neither included in the utility's application nor noticed to its customers? Why would the Legislature require the rate increase notice to "state the amount of the proposed increase expressed in both dollar and percentage terms" (Section 454 (a)) if the amount granted in response to an application may exceed the noticed amount? What are we to tell the customer who felt that a proposed increase was at the level of his ability to tolerate in silence, but who would have spoken or acted in opposition to the larger, granted increase if he had only known that the larger increase was a possibility?

Without getting into the intricacies of a detailed legal analysis, I suggest that the majority's action today is analogous to a denial of the procedural due process rights of Pacific's customers. (See North Alabama Express, Inc. v. United States, 585 F.2d 783 (5th Cir. 1978). At the core of procedural due process is the requirement of adequate notice and an opportunity for hearing. Here, there clearly was ample opportunity for customers to participate in our hearings. But the customers did not have notice of the potential amount of the actual general rate increase. They were not notified that the BPA rate increase would be addressed and acted on in connection with the general rate case application. Indeed, under the majority's apparent theory, customers need not be told of the maximum possible amount of a rate increase, since the amount of the increase may exceed the amount of the utility's request.

I have two further objections to the majority's opinion. I also disagree with the majority's treatment of the cost of removal of the overburden associated with the Centralia coal plant. With little discussion, the majority abruptly reverses the position adopted in Pacific's last general rate case (D.82-05-042, mimeo. at pp.11-12). The majority did decide that the company's proposals for treatment of a new computer system would be made consistent with Pacific's last rate case; I would have applied the same rationale on the Centralia issue, and would have adopted the staff's recommended approach to the Centralia overburden cost.

Finally, I join Commissioner Vial in strongly objecting to the majority's decision to leave the issue of a regulatory risk premium in rate of return open for future Commission review. In my opinion, it is not appropriate for us to adjust a utility's rate of return for so-called "regulatory risk." The Commission has correctly rejected pleas from the utilities for increased rates of return based on this argument in the past. If we adopted regulatory risk premiums, we would in effect condone, or even reward, bad management--penalties for imprudent utility decisions would be nullified by rewards of higher rates of return.

Priscilla C. Grew

PRISCILLA C. GREW, Commissioner

July 18, 1984
San Francisco, California

28. The increase in rates and charges authorized by this decision is justified and is reasonable; the present rates and charges, insofar as they differ from those prescribed by this decision, are for the future unjust and unreasonable.

29. The rate schedules set forth in Appendix C of this decision will afford PP&L an opportunity to collect the additional authorized revenues in a just, reasonable, and nondiscriminatory manner.

30. The allocation of revenues and design of these rates set forth in Appendix B reasonably reflect the staff's LRIC study, and the rates substantially follow the rate design recommended by the staff, except as noted in the opinion portion of this decision.

31. The staff's calculation of the net-to-gross multiplier is reasonable.

32. The expectation is that PP&L will be unable to earn its authorized return on common equity in attrition year 1985 without an attrition allowance to offset increases in operating costs resulting from continuing high levels of inflation, and an increase in rate base.

33. PP&L will require additional revenues in attrition year 1985 for its California jurisdictional electric operations if the utility is to earn its authorized return on common equity.

34. The joint company and staff recommendation of the use of the Fall 1984 DRI forecast as an attrition methodology is reasonable. It is also reasonable to establish the amount of the additional revenues required during the attrition year by an appropriate advice letter filing in the fall of 1984.

35. The rates adopted in this decision comply with the requirements of § 739 of the PU Code amended by the Sher Bill.

36. The Minority/Female Business Enterprise program is reasonable.

XIII. MINORITY/FEMALE BUSINESS ENTERPRISE PROGRAM

In D.82-12-101, we announced our intention to review the adequacy of each utility's minority/female business enterprise (M/FBE) program as part of the general rate case process. Pursuant to our order, PP&L has filed certain information regarding its M/FBE program. Our Revenue Requirements Division staff has reviewed PP&L's filing and is of the opinion that it basically complies with D.82-12-101.

XIV. FINDINGS AND CONCLUSIONS

A. Findings of Fact

1. By these applications PP&L requests increased rates for its California service territory to yield an aggregate increase in operating revenues of $10,873,000 based upon the test year 1984.

2. PP&L also requests authority to file for a rate increase by advice letter for the year 1985 to compensate it for any attrition of earnings.

3. These applications were duly noticed, and all interested parties were afforded an opportunity to be heard on the issues before us.

4. The relative use method of jurisdictional allocation sponsored by the staff is reasonable to use in this proceeding for purposes of determining PP&L's California revenue requirement for the test year 1984.

5. The amounts of operating revenues, operating expenses, and rate base, as well as each element thereof, shown on Table 2 - Summary of Results of Operations, and the method used in obtaining these amounts as discussed in the opinion, represent a fair and reasonable determination of revenue requirement for PP&L's California operations for the test year 1984.

6. The proper and reasonable level of PP&L's California jurisdictional revenue requirement for the test year is $51.1 million.

7. Present rates are estimated to produce $44.2 million in 1984. PP&L is entitled to a rate increase of $6.9 million, which will produce operating revenues of $51.1 million during the test period.

8. For purposes of determining test year 1984 rate of return it is reasonable to impute the following capital structure to PP&L: 56% long-term debt; 12% preferred stock, and 36% common equity.

9. A cost of long-term debt of 9.86% and a cost of preferred stock of 10.92% are reasonable for test period purposes.

10. No consideration should be given to the effects of the abandoned nuclear projects in determining the cost of common equity capital to PP&L for the test period while the appeals to D.84-05-097 are pending.

11. The reasonable cost of common equity to PP&L for the test period is 15.75%.

12. A rate of return of 12.11% is fair and reasonable to apply to PP&L's rate base to obtain net operating revenue for the 1984 test year and 1985 attrition year.

13. Estimated revenues based on the sales forecast for test year 1984 and attrition year 1985 are subject to significant fluctuation.

14. Because of the difficulties inherent in estimating test year electricity sales and the need to protect the ratepayer and the utility from an incorrect estimate, it is reasonable to establish an ERAM for electric sales.

15. The purpose of the ERAM authorized here is to offset the effects of inaccurate estimating. It is not intended to offset the effects of the so-called billing lag which occurs during the first month that a rate increase is effective.

16. A factor contributing to inaccuracy in estimating electricity sales is the difficulty in quantifying the effects of conservation.

17. The adoption of an ERAM will minimize any disincentive toward PP&L's promotion of cost-effective conservation programs.

18. The ERAM tariff provisions shown in Appendix B are reasonable.

California electric operations. We must also take cognizance of the fact that we are today issuing a decision for test year 1984, now half over. In recognition of that as well as the factors mentioned above and all of the evidence in this record, we believe that a return on common equity of 15.75% is fair and reasonable. While 15.75% is 25 basis points higher than the top of the range recommended by our staff, we feel that the extra basis points are equitable in light of the delay in issuing this decision. To avoid similar problems in the future we direct our Executive Director to review our processes with the goal of developing a general schedule for utilities not now covered by our Rate Case Plan. The Executive Director should consider whether these utilities ought to be covered by the Rate Case Plan or, if not, what steps are necessary to prevent unreasonable delays in processing their general rate case applications.

D. The Issues

The issues presented in this proceeding are listed below in the order in which they are discussed in this decision.

1. Jurisdictional allocation.
2. Sales of electricity forecast.
3. Electric revenue adjustment mechanism.
4. Production expenses other than coal.
5. Cost of coal.
6. Bonneville Power Administration rate increase.
7. Safe harbor lease (Malin-Midpoint transmission line).
8. Treatment of capitalized benefits for tax purposes.
9. Repair allowance deduction.
10. Miscellaneous tax issues.
11. Plant held for future use.
12. Other deferred debits included in rate base.
13. Colstrip Unit No. 3.
14. Cost of equity capital.
15. Effects of abandoned nuclear projects on cost of equity capital.
16. Conservation programs.
17. Long-run incremental costs.
18. Cost allocation to customer classes.
19. Rate design within customer classes.
20. Comparative rates.
21. Notice to the public as to (a) the amount of the requested increase and (b) consideration of the effects of abandoned nuclear projects.

4. PP&L shall carry over into the attrition year 1985 any conservation funding allowed in the test year which remains unexpended at the end of 1984.

This order is effective today.

Dated ________________, at San Francisco, California.

(Utilities to prepare App. B and C)

O P I N I O N

I. SUMMARY OF THIS DECISION

This decision authorizes Pacific Power and Light Company (PP&L) to increase its rates for electricity in its northern California service areas by $6.9 million for the test year 1984. PP&L requested an aggregate increase of $10.8 million in two separate applications, which were heard and decided on a consolidated record.

The decision provides PP&L with a 15.75% base return on equity. This translates to an authorized rate of return of 12.11%. PP&L had requested a 16% base return on common equity plus a minimum of 2.0% risk allowance for the effects of the nuclear abandonments. This decision leaves open the determination of an allowance for the risk effects of our denial of recovery of PP&L's allocated share of the cost of the two abandoned nuclear generating projects. Decision 84-05-097, which denied recovery, is on appeal and we do not want to prejudge the outcome of that case. Further, a second Application for Rehearing is pending before us. We will want to consider all implications before assigning or not assigning a risk factor.

Because of the difficulty in estimating total electric sales for the test year, we have followed the pattern we have adopted for other California electric utilities. This decision establishes for PP&L an electric revenue adjustment mechanism (ERAM) which will adjust electric rates for changes in operating revenues from unexpected fluctuations in sales. To the extent that sales of electricity are higher or lower than forecasted, PP&L or its ratepayers will be made whole.

PP&L is authorizing to file for an attrition allowance in 1985 which will reflect the most recent estimates of changes in the level of operating expenses resulting from inflation.

The decision puts into effect for PP&L standard baseline (lifeline) allowances as required by the Sher Bill which was enacted by the legislature in 1982. The baseline rate becomes the first tier of the two-tier residential rate structure.

II. INTRODUCTION

A. Procedural Background

On May 25, 1983, PP&L filed A.83-05-52, which requests Commission authorization of a general increase in electric rates of $6,034,000 based upon the utility's estimate of test year 1984 results of operations. On July 8, 1983, PP&L filed A.83-07-17, which requests authorization of a further rate increase to yield an additional $4,913,000 in revenues based upon the utility's projection of changes in electricity consumption for the 12-month period ending July 31, 1984. A.83-07-17 also asks the Commission to authorize an ongoing ERAM to provide for future increases or decreases in PP&L's rates based upon the relationship of actual electricity sales to the corresponding test year revenues adopted in general rate cases.

At the prehearing conference held on July 29, 1983, the presiding Administrative Law Judge (ALJ) directed that A.83-05-52 and A.83-07-17 be heard on a consolidated record. According to PP&L the total rate increase which the utility is requesting amounts to $10,873,000 for the test year 1984 when the revenue effects of the two applications are combined on a consistent basis.

B. Public Hearings

In early October, two days of hearings for public witness testimony were held before ALJ Haley in Crescent City and two days in Yreka, with an evening session being held at each location. Altogether, about 400 PP&L ratepayers attended these hearings, and of that number over 50 persons made statements in opposition to the rate increase. Following the public witness hearings, 11 days of evidentiary hearings were held in San Francisco, concluding with oral argument on December 13, 1983 when the matter was taken under submission subject to the filing of briefs on January 6, 1984.

In addition to the utility and the staff (both of whom introduced complete results of operations studies and participated in the resolution of all issues) five other interested parties entered appearances and participated in portions of the public hearings: California Farm Bureau Federation (CFBF), Toward Utility Rate Normalization (TURN), Congressman Douglas H. Bosco,[1] and the Siskiyou Cattlemen's Association and Klamath Basin Haygrowers.

C. PP&L's Operations

PP&L is a large diversified corporation. Its widespread operations encompass three distinct business sectors: (1) electric generation, transmission and service; (2) telecommunications and related technologies; and (3) mining and resource development. Of the three , the electric utility sector is by far the largest. PP&L's electric operations serve over 650,000 customers, only about five percent of whom are located in California's three northern border counties of Del Norte, Siskiyou, and Modoc. The other 95 percent are situated in Idaho, Montana, Oregon, Washington, and Wyoming. As an electric utility, PP&L operates 33 hydro generating stations as well as four major steam plants. Its telephone subsidiary, Pacific Telecom, is the fifth largest non-Bell telecommunications company in the county, providing service in six northwestern states and Alaska. Its wholly owned subsidiary, NERCO, one of PP&L's resource development and exploitation activities, operates 10 coal mines in five states. PP&L's consolidated corporate revenues in 1982 were $1.4 billion, of which California jurisdictional sales of electricity accounted for less than $50 million.

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[1] Congressman Bosco represents the First Congressional District in the United States House of Representatives. His participation in this proceeding is on behalf of his Del Norte County constituents.

In D.82-12-071, we charged our staff with taking the lead in moving toward a concensus among the states in developing a revised allocation methodology which would be acceptable to each of the jurisdictions. According to staff testimony in this proceeding, the staff has on several occasions since the issuance of that decision participated in meetings and communicated by correspondence with the representatives of the other commissions concerned with the jurisdictional allocation. The staff witness testified that the various states had not reached a final agreement regarding method; however, at a meeting of state representatives held July 15, 1983, there was a general concensus that favored the methodology of the NARUC Electric Cost Allocation Manual published in 1973.

It is apparent that the "final agreement" we had hoped for will not be realized in the foreseeable future, if ever. In the meanwhile, we have grown increasingly concerned as to the appropriateness of the relative-use method we adopted as an interim measure in the last rate case. In that rate case, the difference in annual revenue requirements determined by the coincidental peak allocation method and the relative use method was only $585,000. This difference has grown to $1,210,000 in this proceeding, and the indications are that this difference will continue to grow. It would seem to ensue, therefore, that an ever increasing portion of PP&L's plant investment and operation costs will be relegated to a jurisdictional no-man's land with an undesirable impact on PP&L's credit and its cost of money. Our original purpose, which was to assure Californians would bear no unjustified rate burden, would not be met, and thus our allocation endeavors could be self defeating.

The staff witness testified that the only reason that the NARUC method was not reflected in the staff's presentation was that concensus reached at the July 15, 1983 meeting occurred too late for this proceeding. Although no party sponsored an allocation based on the NARUC methodology, the sketchy evidence of record shows that it would probably result in an allocation of about 3.94% to California compared to 3.88% for the coincidental peak method. Viewed in this light, PP&L's allocation method appears to produce a conservative and reasonable allocation to California. However, PP&L did not present sufficient evidence to cause us to abandon the relative-use method of allocation for purposes of determining the revenue requirement in this proceeding.

At this time, we are placing PP&L and our staff on notice that in the utility's next rate case, the showing of each should include, in addition to whatever methodology they may prefer, an allocation study based on the concensus methodology using the 1973 NARUC allocation manual as well as an allocation based upon the relative-use method.

IV. OPERATING REVENUES

A. Sales of Electricity

The staff differs with PP&L's electricity sales forecast with respect to industrial sales and special sales for resale. The staff estimates test year 1984 industrial sales at 65,500 megawatthours (MWh), or at a level 11.3% higher than PP&L's figure of 57,905 MWh. This difference in sales forecasts equates to a revenue requirement difference of $498,000 for the test year.

At the hearings, the PP&L load witness testified that nine months of actual experience subsequent to the date on which the sales estimate was made shows the utility's forecast for California sales to be within one percent of actual experience, with the actual loads experienced being below those forecast. This witness testified further that his best current estimate of loads would result in the utility sponsoring a lower sales forecast if afforded the opportunity.

The staff's higher estimate of 1984 industrial sales customers results in part from its prediction of a greater economic recovery, particularly in the region's logging and wood products industries, and in part from the staff's use of a different forecasting method.[2]

The record shows that PP&L's actual experience has been that sales to industrial customers during the first nine months of 1983, exceeded its forecasted sales by 39%. PP&L's rationale for this development is that the higher sales were not a result of an upsurge in the economy of the area but, instead, resulted from the reopening of one paper mill and a higher-than-forecasted level activity at a new gold mine.

We are of the opinion that the present and near-term trends in the economy of California give greater support to the staff forecast of industrial sales than to that of PP&L. These encouraging economic trends, plus the fact that the staff's forecast is based on later load data than the utility's forecast, convince us that we should adopt the staff estimate of electricity sales for the test year 1984.

We note PP&L's objection to the fact that the cost effect of the staff increase in the sales forecast was not carrried through to other portions of the staff case. PP&L is correct in its assertion that the staff has made no parallel adjustment to recognize

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2 The staff position on economic trends through 1984 was based in part on the June 1983 forecasts from Data Resources, Incorporated (DRI) and the Summer 1983 UCLA Business Forecasting Project. PP&L's forecasts were prepared in October 1982 and were not subsequently changed. The staff forecast of industrial sales was made using a different methodology than PP&L employed. The staff used a macroeconomic equation for the period 1970-1983 by quarters to develop its estimates. PP&L relied mainly on cross-sectional econometric equations to model changes in the industrial sector.

establishment of: (1) a "cap" on ERAM so that PP&L does not exceed its authorized rate of return; and (2) a range of revenue fluctuation of one to two percent around which the mechanism would not be triggered.

PP&L disagrees with the second of the staff's suggested modifications to the ERAM proposal. PP&L contends that it is difficult to tell how the staff would compute this range. PP&L brings out that the staff witness testified at one point that a $2.1 million undercollection in 1982 would represent only a negative 0.93% undercollection and, at another point that an $0.5 million undercollection at a higher revenue was equivalent to a one percent undercollection. PP&L emphasizes that the staff has sponsored a sales forecast approximately one percent greater than the utility, with this difference representing approximately $500,000 in revenues. PP&L reasons that, if the staff ERAM range proposal were adopted and if actual sales prove to be equal to the utility's forecast, a substantial revenue loss would occur which could not be corrected through the ERAM . PP&L argues that such an undercollection would be much more likely than any overcollection because, it asserts, even its lower forecast of California sales is turning out to be greater than actual sales. PP&L's position is that its customers would be adequately protected by the establishment of a cap preventing returns over those authorized and that, therefore, the staff's additional proposal a triggering range should be rejected.

Congressman Bosco's representative, as well as a number of the participating members of the public, oppose the establishment of an ERAM mechanism. They contend that it would result in too-frequent rate increases, that it would detract from the conservation effort, and that it would shift the stockholders' risk to the ratepayer. These issues are not unique to PP&L's situation; they are generic to the ERAM concept. We are of the opinion that any such effects on PP&L would, as they are for the rest of the California electric utility industry, be more than offset by the advantages that accrue to the ratepayer and stockholder alike.

Accordingly, we will deny Congressman Bosco's motion to dismiss PP&L's ERAM application. We will adopt PP&L's proposal. We will not adopt the staff's recommendation for a range of revenues as a triggering device for the ERAM or for the establishment of a cap as this would be a departure from established ERAM procedure. We may, however, wish to examine the concept of a cap on ERAMs in some future generic proceeding.

V. OPERATING EXPENSES

A. Production Expenses Excluding Coal

There is a difference of $348,000, after allocation to California, between the PP&L and staff estimates of 1984 production expenses at the utility's coal plants, excluding the cost of coal. PP&L and the staff agree on the escalation rate to be used to forecast 1984 budgets, but they do not agree on the 1983 base figure to be escalated. PP&L used its actual 1983 steam plant budget as a base figure. The staff, on the other hand, derived its 1983 base by escalating 1982 actual expenses by the percentage change between PP&L's 1982 and 1983 budgets.

The staff brings out certain problems associated with PP&L's proposal to use the 1983 plant budgets as the base amount. One problem is that the 1983 budgets were created in 1982 before many of PP&L's recent cost control measures were adopted; therefore, the 1983 budgets are a less accurate indicator of actual 1983 expenses than the utility's 1982 recorded expenses. Another problem for 1983 was deferred so that PP&L could keep its dividends high. The staff accuses PP&L of deliberately taking an unwarranted risk which resulted in the deterioration of electric plant in order that the utility would not have to reduce its dividend.

We agree with the staff position that the ratepayers should not be called upon to pay the additional costs associated with a decision which PP&L appears to have taken solely for the benefit of its stockholders. Accordingly, we will adopt the staff estimate for production expenses (excluding fuel) for coal-fired generating plant. This is the only portion of test-year production expenses (other than the cost of coal and the jurisdictional allocation) which remained at issue at the time of submission.

B. Cost of Coal

PP&L and the staff presented substantially different estimates of 1984 test year coal costs for the utility's Centralia, Dave Johnston and Wyodak steam-electric generating stations, the significant portion of the difference relating to the Centralia plant. The staff's estimate of coal costs would produce an allocated test year revenue requirement $324,000 lower than PP&L's. In addition, the staff estimate of coal cost would have the effect of reducing rate base by $65,000 through lowering the investment in coal inventory.

When PP&L prepared the showing it filed with the application, it determined the base price per ton by using actual coal costs recorded during the last four months of 1982 and then factoring the data upward using a December 1982 DRI escalation forecast. The staff used a similar approach to determine its base price. However, the staff used the average cost of coal during all of 1982 and escalated the data using a July 1983 DRI forecast.

We will adopt the utility's estimate for the cost of coal. During the hearings PP&L presented testimony showing the recorded 12-month average price for coal at Centralia as of August, 1983 to be $20.06 per ton. Escalating to a 1984 level of expense would result in a price for coal very close to PP&L's estimate of $21.30 per ton for 1984. We will also allow an additional $7,000 in test year fuel costs to reflect an allocation of higher fuel consumption related to the greater megawatt sales reflected in the revenue figure we are adopting.

C. Purchased Power Expenses

In early October, during the course of the hearings in these proceedings, PP&L learned of the Bonneville Power Administration (PBA) intention to increase the rates it charges PP&L for electric power effective November 1, 1983. PP&L shortly thereafter introduced Exhibit 20A containing Table 20A-11C which detailed the revenue requirement effect of the imminent BPA increase. The staff immediately moved to strike this table on the grounds that it was introduced without notice to interested parties and in an untimely manner without a showing of good cause. The presiding ALJ denied the motion, and at this time that portion of the staff's petition of November 14, 1983 relating to BPA is still pending.[3] In his opening brief, staff counsel continues to maintain his position in opposition to the inclusion of the BPA increase in the determination of PP&L's test year 1984 revenue requirement.

Table 20A-11C of Exhibit 20A shows the impact of BPA's proposed increase on 1984 test year results of operations for California to be $719,000. This figure was reviewed and accepted by the staff. Subsequent to the PP&L and staff presentations on this issue, the Federal Energy Regulatory Commission (FERC) suspended the portion of the BPA increase relating to wheeling expenses. In recognition of this suspension, PP&L and the staff removed the transmission portion of the BPA increase from Exhibit 53, the joint utility staff exhibit which compares their respective estimated

[3] The staff's November 14, 1983 petition requesting the Commission to overrule the ALJ is discussed in greater detail under the side-heading "Colstrip Unit Number 3", infra.

"1. The total construction cost of the plant to PP&L was $181,023,000, including $34,758,000 of overheads which PP&L had previously deducted for tax purposes leaving a tax basis cost of $146,265,000. The selling price to Amoco was the tax basis cost of $146,265,000 derived above.

"2. Amoco made a downpayment of $43,869,094 and will pay the balance of $102,395,966 to PP&L over 30 years at an annual interest rate of 17%.

"3. PP&L's lease payments to Amoco are exactly equal to Amoco's loan payment to PP&L. In effect, after the payment of $43,869,094 there are no further cash transactions between PP&L and Amoco."

The staff views the effect of this transaction simply as a reduction of PP&L's $181 million investment in the transmission line by $44 million, leaving an actual investment of $137 million in the transmission line. It is the staff's position that only this $137 million remainder should be included in rate base. Further, the staff arrives at a net plant investment, on a tax basis, of $102 million ($146 million less the $35 million previously deducted) and imputes normalized tax depreciation for ratemaking using this $102 million tax basis.

PP&L presents its case as if it had continued to retain the related tax benefits. PP&L points out that this position is consistent with both its and the staff's treatment of the safe harbor lease which the Commission adopted in D.83-03-059 in the utility's last general rate case. PP&L contends that the staff, in departing from the previously adopted treatment, is taking two mutually inconsistent positions; (1) the staff recognizes that the tax benefits were sold by reducing rate base by the $43 million cash payment received from Amoco; and (2) it then reverses its field and imputes some of the tax benefits that were sold to further reduce the utility's revenue requirement.

We agree with PP&L's assertion that this treatment "double counts". Staff's position is self-contradictory; its parts are mutually opposed. The staff cannot both reduce rate base by the proceeds from the sale of the tax benefits and then continue to apply the tax benefits to further reduce the revenue requirement. For adopted test year purposes, we will reduce PP&L's rate base by the $44 million payment received by Amoco; however, we will determine income taxes for rate fixing purposes without imputing any tax benefits associated with the investment tax credits and income tax depreciation which were sold to Amoco in consideration of the $44 million payment. In this manner, the ratepaying public will receive the full benefit of the proceeds of the safe harbor lease.

E. Treatment of Capitalized Benefits and Taxes for Tax Purposes

The staff reduces its estimate of test year 1984 tax expenses by deducting certain employee benefits and taxes other than income which PP&L elects to charge to construction and capitalize rather than take the option provided by law of expensing those costs. The staff assumes that PP&L has expensed these items for tax purposes. In its brief, the staff stipulates to the utility's treatment of life insurance expenses, thus removing employee benefits from this issue.

staff did not recognize state deferred taxes for ratefixing purposes, thus reducing the test year revenue requirement by $64,000. The staff position agrees with our stated policies on the issue; therefore, we will adopt the staff treatment on this issue.

As to the third of these miscellaneous tax issues, the staff witness testified that the tax benefits of 1981 and prior investment tax credits have been flowed through. However, in OII-24, we adopted normalization of ITC generated in 1981 and thereafter in order to preserve the requirements of ERTA. Pacific has recognized this normalization treatment by amortizing 1981 ITC over a 30-year period, whereas the staff has excluded from its showing the unauthorized balance of 1981. The utility's treatment, which we are adopting for test year purposes, reduces revenue requirement by $218,000; however, it protects the tax benefits provided to Pacific by ERTA.

VI. RATE BASE

A. Plant Held for Future Use

PP&L's rate base estimate includes a relative use allocation amount of $187,000 for plant held for future use (PHFU). The staff has adjusted PHFU downward by $163,000 to exclude from rate base seven properties that will not be placed in service before 1994. These properties include the specific future sites of three generating plants, one substation and the rights-of-way for three transmission lines. The staff takes the position that the seven properties should not be included in PHFU for rate base purposes unless the utility has definite plans to develop them within the next 10 years.

PP&L's witness admitted on cross-examination that the company has no plans to develop any of these sites within the next ten years. The staff's position is simply that property should not be considered as plant held for future use in rate base unless the company has specific plans to develop the property within the next decade. PP&L's position is apparently that any property owned by the utility which may ever become useful should be included in rate base. In our opinion the staff recommendation is reasonable and is consistent with recent Commission policy. Accordingly, we will adopt the staff exclusion of PHFU.

B. Other Deferred Debits
Included in Rate Base

PP&L has included in rate base $575,000 representing the allocated costs of certain items which the utility asserts are now providing service or are part of past costs incurred to provide service. These items include computer system expenses and the cost of overburden removal at Centralia coal mine. The staff has removed $549,000, or practically all of these costs, from rate base. The staff has, however, included $38,000 in amortization expenses to reflect the amortization over a four-year period of California's allocated portion of $3.5 million in computer system costs.

On a system basis, PP&L has incurred $11.3 million in costs associated with removing overburden (topsoil, rocks and vegetation overlying the coal seams) at its Centralia mine. These costs are expensed over the period during which the coal is burned. It is the staff position that these unamortized costs should not be included in rate base. PP&L has capitalized these expenses in order to recover its carrying costs; the staff treatment, on the other hand, gives no recognition to the heavy costs which PP&L has sustained in the development of the coal mine.

We will adopt the ~~staff~~ company treatment of the computer system expenses. We have, however, re-examined the overburden issue, and it is our opinion that the ratepayers are the ultimate and obvious beneficiaries of the orderly and economic removal of the overburden at Centrailia mine. Equity requires that we recognize the large investment PP&L has made in preparing its coal mine to be advantageously exploited in order to provide coal to the ratepayer economically. Accordingly, we will allow the allocated costs of the removal of Centralia overburden to be included in test year 1984 rate base.

C. Colstrip Unit Number 3

Exhibit 20A was introduced by PP&L on October 19, 1983. Table 20A-11C of that exhibit presents test year 1984 effects of a November 1, 1983 rate increase by the BPA, and Table 20A-11D shows the effects of the inclusion of Colstrip Generating Station Unit 3 and related transmission plant (Colstrip 3) in rate base. Staff counsel made an oral motion to strike Tables 20A-11C and 20A-11D together with related oral testimony and to limit the further hearing set for December 12, 1983 to issues other than consideration of the Colstrip 3 in this rate case. The presiding ALJ denied staff's motion, and on November 14, staff counsel filed a petition requesting that the Commission overrule the ALJ.[4]

[4] Previously, on October 20, 1983, staff counsel filed a petition urging the Commission to overturn a ruling of the presiding ALJ which denied staff counsel's motion to strike PP&L's Exhibit 9 and Exhibit 10. We have considered staff counsel's October 20 petition, which has not heretofore been ruled upon, and we conclude that it should be denied.

VII. RATE OF RETURN

Rate of Return

Next to jurisdictional allocation, the issue of rate of return is the element of the estimated 1984 results of operations involving the largest revenue requirement difference between the utility and staff showings, i.e., $871,000 on an allocated test year basis. Table 1 is a comparison of the cost of capital estimates of PP&L and the staff together with the figures we are adopting for purposes of determining authorized rate of return for the test year 1984.

As Table 1 shows, the two parties imputed the same capial structure in their determination of rate of return, i.e., 52% long-term debt, 12% preferred stock and 36% common equity. In our opinion this capital structure is reasonable for this utility, and we will adopt it for purposes of 1984 test year results.

TABLE 1

Pacific Power & Light Company
Cost of Capital
Test Year 1984

Component	Capital Ratio	Cost	Weighted Cost
PP&L			
Long-Term Debt	52.00%	10.25%	5.33%
Preferred Stock	12.00	10.99	1.32
Common Equity	36.00	16.00	5.76
Total	100.00%		12.41%
Staff			
Long-Term Debt	52.00%	9.86%	5.13%
Preferred Stock	12.00	10.92	1.31
Common Equity	36.00	15.00-15.50	5.40-5.58
Total	100.00%		11.84-12.02%
Adopted			
Long-Term Debt	52.00%	9.86%	5.13%
Preferred Stock	12.00	10.92	1.31
Common Equity	36.00	15.75	5.67
Total	100.00%		12.11%

B. Abandoned Nuclear Generating Projects

On November 15, 1983, the ALJ issued a written ruling taking official notice of D.83-11-012, which the Commission issued on November 2, 1983 in A.82-07-82. In that application PP&L requested authority to increase its California rates to recover its investment in two abandoned nuclear generating projects. The two projects are the Pebble Springs Nuclear Project, in which PP&L held a 29.4% interest, and the Washington Public Power Supply System Nuclear Plant No. 5, in which PP&L held a 10% interest.

D.83-11-012 ordered as follows:

> "1. PP&L's request to amortize the costs of the abandoned Pebble Springs and WNP-5 projects is denied.
>
> "2. The issue of risk to shareholders associated with the denial of amortization of abandonment losses shall be considered in determining the reasonable rate of return in PP&L's general rate case proceeding.
>
> "3. The ratemaking treatment to be accorded the gain resulting from the debt/equity exchange shall be considered in PP&L's next general rate case proceeding."

The ALJ's ruling enlarged scope of the hearing scheduled for December 12, 1983 in this proceeding to include the pertinent issues arising from D.83-11-012. At the December 12 hearing, parties so desiring were afforded the opportunity to present prepared testimony and/or exhibits as well as to conduct cross-examination relating to these additional issues.

On November 30, 1983, PP&L filed an application for rehearing of D.83-11-012. On May 16, 1984, we issued D.84-05-097 in the matter of the application for rehearing. D.84-05-097 made substantial modifications to D.83-11-012. PP&L has filed an application for Rehearing of D.84-05-097 as well as a Petition for Writ of Review (S.F. 24741) with the California Supreme Court. Because these proceedings are pending we will not decide the issues which arose in D.83-11-02 at this time but will hold them open for further review when the basic abandonment question is settled.

On June 1, 1984, the Commission staff petitioned the Commission to set aside and reopen this proceeding because of the issuance of D.84-05-102. We regard the action of reopening the proceeding as unnecessary, and we will deny staff's petition.

VIII. CONSERVATION PROGRAMS

PP&L regards itself as a leader in the conservation area, in which it has been active for over six years. The utility believes, and the staff agrees, that it would not be beneficial to its ratepayers either to terminate all of its conservation programs or to drop any particular program. PP&L and the staff concur, however, that conservation programs should be subject to continuing evaluation as to which are most cost effective. They also agree, that with the modifications proposed in this rate case, the existing programs should be continued through 1985. They believe that, given the staff's proposal for flexibility in funding the present programs, PP&L will be afforded the opportunity to promote the most cost effective programs even before any major revisions that may become effective after 1985.

During the next two years our staff will make reviews and recommend which programs should be terminated or continued beyond that date, as well as which programs should be added. In this proceeding, the staff has recommended modifying several programs and adding new programs which are currently authorized for other

In addition, we see no reason why the long run incremental cost used to allocate revenue requirements should not also be utilized in evaluating the cost-effectiveness of conservation programs that produce long-run energy savings. Parties are directed to present both sets of cost-effectiveness analysis in PP&L's next general rate case--one based on the short-run avoided cost methodology adopted in Decision 83-11-047 and one based on the long-run incremental cost methodology adopted for allocation purposes in this proceeding.

The total conservation budget recommended by the staff is $699,000 as compared to PP&L's initial request of $644,000. The main reasons for the staff recommending a higher figure are so that PP&L can: (1) create a direct weatherization program, (2) offer rebates to encourage customers to purchase energy efficient refigerators, and (3) participate in the "one warm room" program. The staff also believes that all monies allocated to home energy audits (HEA) not resulting in customer participation in one of PP&L's incentive programs should be charged to the HEA programs. The staff recommends that in the future all HEAs be accounted for separately and that the utility should note those HEAs which resulted in customers participating in other conservation programs.

The staff recommends that PP&L be required to furnish this Commission with brief quarterly reports illustrating the utility's expenses, accomplishments and expected annual energy saving attributed to each conservation program. It also recommends that PP&L continue its monitoring of energy savings using meter read data and be permitted management discretion to transfer up to $200,000 to more effective programs after consultation with the staff. Such a reallocation of funds may be necessary if the direct weatherization program, the rebate program, the efficient refigerator rebate program or the "one warm room" program have more demand than expected.

We will expect PP&L and our staff to work closely during 1984 to effect the policy we have outlined above. Any problems with the program should be brought to our attention immediately through the advice letter filing procedure for our review and resolution.

Consistent with our "stay the course" policy adopted for SDG&E and PG&E, we will not adopt staff's recommendation to initiate a rebate program for energy efficient refigerators and portable heaters for a "one warm room" program. In Decision 83-12-065, the Commission determined that these programs were not cost-effective. Further, the refigerator rebate program is not particularly accessible to low income ratepayers. However, PP&L can produce written information on ways to reduce heating costs by the use of "one warm room", from its regular conservation education budget.

In order to enable greater participation of low-income families to the weatherization program, and reduce administrative costs, we will authorize the direct weatherization program recommended by staff. It is expected that PP&L will identify and weatherize at least 50 low income homes in its service territory, with costs at or below $800 per home. PP&L is directed to keep accurate records on costs and energy savings for review by this Commission in PP&L's next general rate case.

Our adopted expenses for PP&L's conservation programs for the test year will be $679,000. This amount specifically excludes any funding for the one warm room and the energy-efficient refigerator programs. We will also authorize PP&L to transfer up to $100,000 for more effective programs following written notification of and agreement by the Executive Director. We also place PP&L on notice that we will give consideration to carrying over to the next general rate case the effects of any unspent conservation funds which were allowed for rate fixing purposes. We will direct the utility to submit the quarterly conservation reports recommended by the staff.

IX. ADOPTED RESULTS OF OPERATIONS

Although other parties participated in some aspects of the results of operations portion of this proceeding, only PP&L and the staff presented complete results of operations estimates upon which to determine the revenue requirement of the utility for the test year 1984. Table 2 shows the comparative estimates of PP&L and the staff at present rates, as finally presented in their joint late-filed Exhibit 53. Also shown for the test year on Table 2 are the adopted results of operations at authorized rates.

The adopted results reflect our determination of the individual issues as discussed in the preceding portions of this decision. The adopted results reflect the figures shown in Exhibit 53 with one exception, production expenses. Our adopted results, as we indicated in the earlier discussion, include the test year effects of the recent BPA rate increase at $719,000, rather than at $483,000 as reflected by PP&L and the staff in their comparative exhibit.

TABLE 2

Summary of Results of Operations
Comparison Test Year 1984
California Jurisdictional
(Thousands of Dollars)

	Present Rates			Authorized
	PP&L	Staff	Adopted	Rates
Operating Revenues				
Gen. Business Sales	$ 39,088	$ 39,590	$ 39,590	$ 46,535
Special Sales	4,449	4,159	4,159	4,159
Other Oper. Rev.	421	421	421	421
Total Oper. Rev.	43,958	44,170	44,170	51,115
Operating Expenses				
Production	15,581	14,407	14,682	14,682
Transmission	1,586	1,495	1,728	1,728
Distribution	2,344	2,344	2,344	2,344
Customer Accounts	978	978	978	978
Customer Serv.& Info.	589	589	569	569
Admin. & General	3,393	3,393	3,393	3,393
Subtotal	24,471	23,206	23,694	23,694
Depr. & Amort.	4,583	4,466	4,459	4,459
Taxes Other Than Income	2,065	2,016	2,016	2,102
State Income Tax	537	335	608	1,267
Net Fed. Inc. Tax	2,695	3,497	3,304	6,156
Deferred State Tax	40	-	-	-
Subtotal Tax	5,337	5,848	5,928	9,525
Total Oper. Exp.	34,391	33,520	34,081	37,678
Net Revenue	$ 9,567	$ 10,650	$ 10,089	$ 13,437
Rate Base	$114,976	$111,001	$110,960	$110,960
Rate of Return	8.32%	9.59%	9.09%	12.11%

X. ATTRITION

A joint exhibit was filed by the company and staff in which they agreed to use the Fall, 1984 DRI forecast for escalation of labor and non-labor expenses as a methodology for determining 1985 attrition. We adopt this methodology and those factors should be applied to the adopted 1984 expenses. We also adopt staff's recommendation that the 1984 expenses should first be shown in 1983 dollars and escalated for both 1984 and 1985. This would correct for any errors in 1984 escalation factors.

The company, in its brief, stipulated to all of staff's attrition calculations which include no financial attrition and $459,000 to cover additional capital costs. We will adopt staff's position.

PP&L is instructed to file an advice letter on or before October 15, 1984, setting forth the additional revenue requirement as a result of its increased expenses and capital costs. Any differences in revenues associated with increased or decreased sales in 1985 will be recovered through the ERAM procedure we establish today. We will also consider actual wage increases due to labor contracts negotiated prior to the filing of the advice letter.

The staff's nominal discount rate of 15% is based on a cost of common equity which is higher than that recommended by any other party to the proceeding. However, the staff explicitly pointed out that the 15% nominal cost of capital should be considered a lower bound for proper nominal discount rate to be used in this proceeding.

On balance, we believe that the staff LRIC study develops and uses a more realistic carrying charge than PP&L. It is our opinion, therefore, that for rate spread purposes the staff's discount rate would result in electricity user's paying closer to the same amount in real terms for each year that a given facility is in use.

Another significant difference between the two LRIC studies relates to PP&L's providing a 15% reserve margin by adding a gas turbine, whereas the staff did not allow for such an addition. We agree with the staff's position on this point which is stated in Exhibit 40, as follows:

> "PP&L added a 15% reserve margin to the long-run incremental unit cost where staff did not. The 15% reserve margin was not used because the combustion turbine is used to determine the demand component of a coal plant. Since there was no reserve margin used in the calculation of the coal plant, staff felt that this was inconsistent."

B. Allocation to Customer Classes

Both PP&L and the staff calculate marginal customer costs for each class of customer. The staff, however, in using its study in preparing their LRIC studies, for spreading the revenue requirement among the customer classes, ignores marginal customer costs and recognizes only marginal energy and demand as appropriate cost elements for their purposes. PP&L takes exception to this treatment, arguing that customer costs were actually incurred by the utility in providing service, and that they varied by customer class. PP&L argues that the impact of ignoring customer costs in the rate spread process results in unfairly removing a bona fide revenue requirement burden from some customer classes and placing it on others.

The staff rationale for excluding customer costs from the rate spread determination is that customer costs do not vary with the demands customers place on the system (at different time-of-use periods) and are therefore inappropriate to include for this purpose. This staff view coincides with the treatment we have adopted in electric rate cases with some degree of consistency over the past several years. While the evidence shows that in PP&L's case these customer costs when expressed on a per-customer basis vary by customer load classes, this does not mean that such costs are load related. To conclude that these costs were load related, it would have to be shown that cost per kW varied systematically across the load classes. Furthermore, any such kW cost variation should be assigned to variable distribution rather than to customer costs in a properly conducted incremental cost study.

On each of the points of major difference between the utility and the staff LRIC studies, the weight of the evidence supports the staff's study as possessing greater merit for purposes of this proceeding. Accordingly, we will use the staff's LRIC study as the basis for allocating costs among customer classes and for the design of rates. However, to moderate rate changes between classes of service, we will only move a portion of the way toward an incremental cost allocation in this proceeding (20% incremental cost weight: 80% system average percentage weight). Due to the incomplete showing as to the proper development of incremental costs to be applied to irrigation (PA-20) customers, we will simply maintain the relationship between PA-20 rates and the overall system rate by allocating revenues to this class based entirely on the system average percentage increase.

The staff recommends retaining PP&L's existing two-block rate structure for residential rate at 80% of the system average rate as described in Exhibit 40. The staff also studied the impacts of setting baseline rates at 75% and 85% of system average rates. We have reviewed these staff recommendations, as well as those of PP&L, and we conclude that the 80% factor favored by the staff is a fair and reasonable level at which to fix baseline quantity rates.

2. General Commercial and Industrial Rates

The bulk of PP&L's commercial and industrial customers are served under two schedules: Schedule A-32 for demands of up to 100 kW and Schedule A-36 for demands of between 100 and 500 kW. These schedules provide for three types of charge: basic charge, demand charge, and energy charge. The basic charge is determined from the average of the two highest monthly demands of the preceding year. Its purpose is the recovery of a portion of billing and commitment expenses. The demand charge reflects the fixed and variable costs related to load on the system. The energy charge reflects the fixed and variable costs which are a function of the energy use.

The staff believes that these two rates do not appropriately reflect the LRIC associated with the different classes of small and medium-sized customers. The staff therefore recommends that the Commission: (1) create a new schedule to be designated A-32A) for low demands; and (2) modify Schedules A-32 and A-36 and eventually merge them into one schedule. Under the staff proposal, Schedule A-32A would be mandatory for customers with demands smaller than 20 kW and optional for demands between 20 kW and 500 kW. Current rates do not reflect the sharp change in LRIC that occurs for demands in the range of 15 to 20 kW.

staff does not believe there is good reason to maintain the present subsidy. It recommends, however, that the level of Schedule AWH-31 be moved only half way toward the weighted average of Schedules A-32 and A-36 because any further adjustment at this time would impose an unjustified burden on the remaining water-heating customers. We adopt the staff position.

5. Irrigation Service

Irrigation customers are severed under Schedule PA-20, which includes three types of charges: (1) a winter demand charge based on the maximum demand occurring during each winter month, or, for smaller demands, the nameplate horsepower of the connected load; (2) an annual charge collected in November, based on the average of the two highest demands established during the previous 12-month period; and (3) declining block energy rates differentiated by season.

PP&L would maintain the annual charge at its current level and increase the demand and energy charges by equal percentages. This approach, which the staff believes is reasonable, would maintain the proportional relationship between the seasonal charges. The staff would, in addition, move the declining-block energy rates of the schedule toward a single block to increase the incentive for conservation.

The CFBC asserts that for California agriculture to remain economically sound and competitive with Oregon agriculture, the Commission must, as it did in D.82-05-42, set irrigation rates at the residential baseline rate. The CFBC points out that PP&L provides its Oregon agricultural customers a credit of 1.4 cents per 1983 seasonal kWh in excess of 1982 seasonal kWh. CFBC contends that this Oregon arrangement has the effect of creating a lower price and increasing the amount of irrigation pumping, and that it will work to the economic detriment of California's agriculture unless

B. Abandoned Nuclear Projects

Congressman Bosco and TURN contend that the public did not receive sufficient notice as to the inclusion in this proceeding of issues relating to the revenue requirement effects of the abandonment of the two nuclear projects in which PP&L was a participating utility. The Congressman and TURN are certainly correct on the technical point that neither of the applications as filed in this rate proceeding specifically treat the issues relating to the abandonment of these projects.

It is a ratemaking reality that the issues and elements that add up to a utility's total revenue requirement are constantly being modified, added to, or deleted from during the course of an extended rate increase proceeding such as this. It would be impractical and self-defeating to proceed otherwise. So long as the duly noticed total revenue requirement sought is not exceeded, it is more often than not necessary for us to recognize and evaluate the effects of events and circumstances occurring subsequent to the filing of a rate increase application. Our issuance of D.83-11-092 in A.82-07-048, supra, is one of a number of such occurrences which have been considered by us in this proceeding without thereby exceeding notice requirements.

In the above respect, nothing unusual attaches to this issue. However, the issues relating to the abandoned projects have been before us and in the public's eye and mind ever since PP&L filed A.82-07-048 on July 7, 1982. That application requested authority to increase PP&L's California electric rates to recover its investment in two abandoned generating projects. Hearings to receive public testimony were held in Yreka and Crescent City on March 17, 1983 and

XIII. MINORITY/FEMALE BUSINESS ENTERPRISE PROGRAM

In D.82-12-101, we announced our intention to review the adequacy of each utility's minority/female business enterprise (M/FBE) program as part of the general rate case process. Pursuant to our order, PP&L has filed certain information regarding its M/FBE program. Our Revenue Requirements Division staff has reviewed PP&L's filing and is of the opinion that it basically complies with D.82-12-101.

In D.84-06-101, our recent decision in the Pacific Bell general rate case, we considered the reporting format recommended by staff and concluded that greater specificity was needed. We required Pacific Bell to report its M/FBE data according to the ethnic classifications used by agencies of the State of California and to break out total contract expenditures and F/MBE contracts for each category in which $5 million of business or more was done in a prior year. We also required Pacific Bell to establish M/FBE goals for 1986 and to file semiannual reports as a means of tracking the company's progress. Pacific Bell was directed to meet with minority group representatives in implementing our decision. We would like PP&L to follow a similar procedure and will direct it to do so in our order.

XIV. FINDINGS AND CONCLUSIONS

A. Findings of Fact

1. By these applications PP&L requests increased rates for its California service territory to yield an aggregate increase in operating revenues of $10,873,000 based upon the test year 1984.

2. PP&L also requests authority to file for a rate increase by advice letter for the year 1985 to compensate it for any attrition of earnings.

3. These applications were duly noticed, and all interested parties were afforded an opportunity to be heard on the issues before us.

4. The relative use method of jurisdictional allocation sponsored by the staff is reasonable to use in this proceeding for purposes of determining PP&L's California revenue requirement for the test year 1984.

5. The amounts of operating revenues, operating expenses, and rate base, as well as each element thereof, shown on Table 2 - Summary of Results of Operations, and the method used in obtaining these amounts as discussed in the opinion, represent a fair and reasonable determination of revenue requirement for PP&L's California operations for the test year 1984.

6. The proper and reasonable level of PP&L's California jurisdictional revenue requirement for the test year is $51.1 million.

7. Present rates are estimated to produce $44.2 million in 1984. PP&L is entitled to a rate increase of $6.9 million, which will produce operating revenues of $51.1 million during the test period.

8. For purposes of determining test year 1984 rate of return it is reasonable to impute the following capital structure to PP&L: 56% long-term debt; 12% preferred stock, and 36% common equity.

9. A cost of long-term debt of 9.86% and a cost of preferred stock of 10.92% are reasonable for test period purposes.

10. No consideration should be given to the effects of the abandoned nuclear projects in determining the cost of common equity capital to PP&L for the test period while the appeals to D.84-05-097 are pending.

11. The reasonable cost of common equity to PP&L for the test period is 15.50%.

12. A rate of return of 12.11% is fair and reasonable to apply to PP&L's rate base to obtain net operating revenue for the 1984 test year and 1985 attrition year.

13. Estimated revenues based on the sales forecast for test year 1984 and attrition year 1985 are subject to significant fluctuation.

14. Because of the difficulties inherent in estimating test year electricity sales and the need to protect the ratepayer and the utility from an incorrect estimate, it is reasonable to establish an ERAM for electric sales.

15. The purpose of the ERAM authorized here is to offset the effects of inaccurate estimating. It is not intended to offset the effects of the so-called billing lag which occurs during the first month that a rate increase is effective.

16. A factor contributing to inaccuracy in estimating electricity sales is the difficulty in quantifying the effects of conservation.

17. The adoption of an ERAM will minimize any disincentive toward PP&L's promotion of cost-effective conservation programs.

18. The ERAM tariff provisions shown in Appendix B are reasonable.

28. The increase in rates and charges authorized by this decision is justified and is reasonable; the present rates and charges, insofar as they differ from those prescribed by this decision, are for the future unjust and unreasonable.

29. The rate schedules set forth in Appendix C of this decision will afford PP&L an opportunity to collect the additional authorized revenues in a just, reasonable, and nondiscriminatory manner.

30. The allocation of revenues and design of these rates set forth in Appendix B reasonably reflect the staff's LRIC study, and the rates substantially follow the rate design recommended by the staff, except as noted in the opinion portion of this decision.

31. The staff's calculation of the net-to-gross multiplier is reasonable.

32. The expectation is that PP&L will be unable to earn its authorized return on common equity in attrition year 1985 without an attrition allowance to offset increases in operating costs resulting from continuing high levels of inflation, and an increase in rate base.

33. PP&L will require additional revenues in attrition year 1985 for its California jurisdictional electric operations if the utility is to earn its authorized return on common equity.

34. The joint company and staff recommendation of the use of the Fall 1984 DRI forecast as an attrition methodology is reasonable. It is also reasonable to establish the amount of the additional revenues required during the attrition year by an appropriate advice letter filing in the fall of 1984.

35. The rates adopted in this decision comply with the requirements of § 739 of the PU Code amended by the Sher Bill.

36. The Minority/Female Business Enterprise program as modified in the above decision is reasonable.

B. Conclusions of Law

1. PP&L should be authorized to file the revised electric rates which are set forth in Appendix C and which are designed to produce $6.9 million in additional base rate revenues based on the adopted test year 1984 results of operations.

2. PP&L should be authorized to file revised electric rates designed to produce additional base rate revenues in the attrition year 1985 in an amount to be determined in October 1984.

3. PP&L should be authorized to file ERAM provisions in its tariffs substantially in the form shown in Appendix B.

4. PP&L should be authorized and directed to make such other changes in its filed tariffs as are set forth in Appendices B and C.

5. The effective date of this order should be the date on which it is signed to meet PP&L's need for immediate rate relief and because a substantial portion of the test year has elapsed.

6. All motions not previously ruled upon should be denied.

ORDER

IT IS ORDERED that:

1. Pacific Power and Light Company (PP&L) is authorized and directed to file with this Commission, on the effective date of this order, revised tariff schedules for electric rates as set forth in attached Appendices B and C.

2. The revised tariff schedules shall become effective on the date of filing and shall comply with General Order 96-A.

3. All motions not previously ruled upon are denied.

4. PP&L shall carry over into the attrition year 1985 any conservation funding allowed in the test year which remains unexpended at the end of 1984.

5. Before January 1, 1985, PP&L shall file a report with this Commission stating its Minority/Female Business Enterprise goals for calendar years 1985 and 1986. Commencing in 1985, on March 1 and October 1 of each year, PP&L shall file a report on the progress made by its M/FBE program. The March 1 report shall cover program activity from July 1 through December 31 of the previous year and the October 1 report shall cover activity from January 1 through June 30. The semiannual reports shall present M/FBE data according to the ethnic classifications used by agencies of the State of California and by contract categories in which $150,000 of business or more was done in the prior year. PP&L shall meet and confer with minority group representatives in preparing their goals and reporting procedures.

This order is effective today.

Dated JUL 18 1984, at San Francisco, California.

(Utilities to prepare App. B and C)

I will file a written dissent.

PRISCILLA C. GREW
Commissioner

I will file a written concurrence.

DONALD VIAL
Commissioner

LEONARD M. GRIMES, JR.
President
VICTOR CALVO
DONALD VIAL
WILLIAM T. BAGLEY
Commissioners

APPENDIX A

List Of Appearances

Applicant: Leonard A. Girard and Nancy M. Ganong, Attorneys at Law, for Pacific Power and Light Company.

Interested Parties: Messrs. Zupancic & Doolittle, by Allen R. Crown, Steven A. Geringer, and Antone S. Bulich, Jr., Attorneys at Law, for California Farm Bureau Federation; Michel Peter Florio, Attorney at Law, for Toward Utility Rate Normalization (TURN); Robert Innes, for Congressman Bosco; and Wayne T. Criss, for Siskiyou Cattlemen's Association and Klamath Basin Hay Growners.

Commission Staff: James E. Scarf, Attorney at Law, and David K. Fukutome.

(END OF APPENDIX A)

Electric Revenue Adjustment Mechanism (ERAM)

No. 1 - Purpose:
The purpose of this Electric Revenue Adjustment Mechanism (ERAM) is to adjust revenues for sales fluctuations.

No. 2 - Applicability:
This ERAM provision applies to all bills for service under schedules and contracts for electric service subject to the jurisdiction of the Commission.

No. 3 - Base Rates:
The Base Rates are the rates for electric service in effect at any time, exclusive of adjustment rates for which a balance or adjustment account is specifically provided in the Preliminary Statement.

No. 4 - Base Revenue Amount:
The Base Revenue Amount is the annual revenue to be collected from Base Rates. The base revenue amount shall be increased or decreased to incorporate changes in the level of authorized revenue specified in decisions of the Commission with respect to Base Rates concurrently with the beginning of the period to which such revenue applies.

No. 5 - Revision Dates:
The Revision Dates are January 1 of each year. On such dates or as soon thereafter as the Commission may authorize, the Utility shall, in accordance with the provisions hereof, place into effect an increase or decrease in the ERAM Adjustment Rate then in effect. Unless otherwise authorized or ordered by the Commission, such increases or decreases shall be made no more than twice in any calendar year.

No. 6 - Electric Revenue Adjustment Account:
Beginning as of August 1, 1984, the Utility shall maintain an Electric Revenue Adjustment Account. Entries shall be made to this account at the end of each month as follows:

(a) A debit entry equal to, if positive (credit entry, if negative)

(1) The applicable Base Revenue Amount multiplied by the applicable monthly factor from the table below, less.

APPENDIX B
Page 2

(2) The amount of Electric revenue for service rendered at base rate, less the authorized energy related revenue:

August	0.094	November	0.073	February	0.087	May	0.078
September	0.086	December	0.086	March	0.081	June	0.086
October	0.069	January	0.094	April	0.077	July	0.089

(b) A credit entry equal to revenue from all applicable sales for service rendered during the month at ERAM Rates if positive (debit entry, if negative).

(c) An entry equal to interest on the average of the balance in this account after entries (a) and (b) above at the interest rate equal to the Company's last authorized rate of return.

No. 7 - ERAM Rate:

The ERAM rate shall be equal to the estimated balance in the Electric Revenue Adjustment Account as of the revision date divided by the estimated sales for the six-month period beginning with the revision date. The ERAM Rates shall be added to the rates otherwise in effect and shall be separately identified in each rate schedule.

No. 8 - Time and Manner of Filing and Related Reports:

The Utility shall file a revised ERAM Rate with the California Public Utilities Commission at least 30 days but not more than 90 days prior to the Revision Date. Each such filing shall be accompanied by a report which shows the derivation of the rate to be applied.

(END OF APPENDIX B)