ALJ/ks

Decision 82-05-042 May 4, 1982

ORIGINAL

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 electric service.	Application 60560 (Filed May 18, 1981, amended September 17, 1981)

Leonard A. Girard, Attorney at Law, for Pacific Power & Light Company, applicant.
Antone S. Bulich, Jr., Attorney at Law, for California Farm Bureau Federation; Michel Peter Florio, Attorney at Law, for Toward Utility Rate Normalization; Nicholas R. Tibbetts, for Assemblyman Douglas H. Bosco; interested parties.
Brian T. Cragg, Attorney at Law, for the Commission staff.

INTERIM OPINION

By this application Pacific Power & Light Company (Pacific) requests Commission approval to increase electric rates for its California service. Pacific's proposed rate schedules, together with special sales and operating revenues, would provide annual revenue of $38,839,000 during test year 1982. The increase over revenue at present rates is $10,347,000, an overall increase of 36.0% and about 39.9% on kilowatt-hour (kWh) sales. Pacific also requests an attrition allowance of $2,451,000 effective January 1, 1983. Pacific amended this application at hearing on September 17, 1981 asking for an additional increase of $44,383 paid to another party on order of the Commission. (Decision (D.) 93371 dated August 4, 1981 in Application (A.) 58605.) This was for advocacy on issues covered by Rule 76.01 of our Rules of Practice and Procedure in Pacific's last rate proceeding.

A prehearing conference was held on August 3, 1981 in San Francisco before Administrative Law Judge (ALJ) Albert C. Porter. Public hearings were held in Yreka, September 14 and 15, 1981, and in Crescent City, September 17 and 18, 1981. Further hearings were held in San Francisco, September 21-25, October 13-16, and October 22, 1981. Concurrent briefs were filed November 13, 1981 and oral replies were heard in San Francisco, November 20, 1981. On December 11, 1981 the Commission staff (staff) submitted a letter to the ALJ supplying a requested reference to the staff position concerning treatment of investment tax credit (ITC). On February 19, 1982, staff filed a motion to reopen the proceedings for receipt of a late-filed exhibit concerning the effects of the Economic Recovery Tax Act of 1981 (ERTA). That motion is granted and the exhibit is received as number 54.

This application is now ready for decision.

Summary

In May 1981, Pacific filed for an increase in its electric rates for consumers in Northern California. The increase requested totaled $10,347,000, an overall increase of about 36%, but about 40% for residential customers and 39% for irrigation customers. There was considerable interest and participation in hearings held on the request by Pacific's California customers particularly since Oregon customers just across the border were due for a 20% rate decrease. That decrease was the result of a new federal law allowing Bonneville Power Agency to reduce rates to certain small users in selected locations in return for increases on other larger users in Bonneville's territory.

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 judgement 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.

The results of operations adopted by the Commission reflect most of the revenue, expense, and rate base adjustments recommended by the Commission's staff. A notable exception is the staff treatment of income taxes, specifically ITC. The position of Pacific is adopted by the Commission because it reflects actual credits available for 1982, whereas the staff version reflects credits earned during 1982. The difference for this rate case is substantial, the staff method resulting in a much higher revenue requirement than requested by Pacific.

The Commission adopts an overall rate of return for 1982 of 12.08% which provides for 16% on common equity. Another factor affecting Pacific's revenue requirement is the Economic Tax Recovery Act (ERTA). The effect of ERTA is to increase the revenue requirement otherwise adopted herein by $277,000.

This decision increases the overall rates in California by $7,175,000 or 27%, applies an overall kWh increase to residential rates, and eliminates the present $2 monthly charge replacing it with a $2 minimum charge while recouping the lost revenue from an overall energy charge increase for residential users. The Commission believes this best reflects its current policies on encouraging energy conservation through use sensitive pricing.

Pacific requested the Commission to authorize an automatic attrition allowance which would increase rates on January 1, 1983. The Commission finds Pacific's attrition proposal to be unreasonable and invites Pacific to request an attrition allowance based on a methodology similar to that adopted by this Commission in its other recent electric utility rate decisions.

Issues

The following is a summary of the major issues in this proceeding in the order they will be discussed in this decision.

1. Jurisdictional Allocations

As they were in A.58605, Pacific's last major rate case, jurisdictional allocations were again a major issue. Toward Utility Rate Normalization (TURN) urged the Commission, as it did in A.58605, to adopt TURN's growth share method of allocation in lieu of the integrated system method used by Pacific. The staff proposed a new allocation alternative, the "relative use" method.

2. Revenue Estimates

Pacific and the staff were the only parties to present complete estimates of results of operations for the test year 1982. For the most part Pacific and the staff are in agreement except for commercial sales. Pacific contends that if the staff commercial sales revenues are correct, then staff has underestimated the amount of service required for the rate year.

3. Operating Expenses

Pacific accepts the staff estimates for operating expenses for the test year 1982 with the exception of an adjustment for purchases of coal from the Bridger Coal Company (Bridger), a wholly owned subsidiary of Pacific. The adjustment proposed by the staff is similar to the one we adopted in the last rate proceeding.

4. Rate Base

The major differences in rate base estimates between Pacific and the staff involve certain unamortized leasehold improvements, removal of overburden at coal mining facilities, relicensing expenses, various special studies, and computer models. The staff estimate for working cash allowance was higher than Pacific's because staff used certain updated information and a later period of time for its estimate.

5. Rate of Return

Pacific requests an overall rate of return of 12.19% for 1982 based on an equity return of 16.25%. Staff recommends between 11.72% and 11.90% overall and 15.25 to 15.75 for equity.

6. ITC

The major difference between Pacific and the staff is the estimate of ITC for test year 1982. The staff estimate of ITC for ratemaking purposes was considerably below that of Pacific, thereby producing a much higher income tax liability. The liability was so much higher that, if the staff estimate were accepted, the revenue requirement would be several million dollars higher than Pacific requested.

7. Rate Design

Again, as in past proceedings, the rate design issues were hotly contested. In general, Pacific recommends a uniform percentage increase and the staff recommends a uniform cents-per-kWh increase. The California Farm Bureau (Farm Bureau) argued strongly against any increases in agricultural pumping charges because of competitive pressures from Oregon agriculture. TURN recommended elimination of the flat residential customer charge, proposing to replace it with increased energy charges for the residential class.

8. Conservation

Staff recommended Pacific's expenses for conservation activities be reduced and that a system of rewards and penalties be instituted based on Pacific's achievement in conservation areas. Pacific claimed that if the Commission adopts this, Pacific should have an opportunity to offer explanations for any failures it may have had in achieving its conservation goals prior to suffering any penalty.

9. Attrition Allowance for 1983

In addition to the 1982 test year increase, Pacific requests another $2,451,000 (6.5%) rate increase to take effect automatically in January 1983. TURN in particular opposes the policy of granting rate increases more than a year in advance based on inflation patterns which may or may not occur.

Allocation Procedures

In D.92411, A.58605, we included an extensive discussion of jurisdictional allocation procedures used or proposed by the parties. In that decision we indicated that we did not support the existing methodology used by Pacific, that we saw merit in the growth share alternative proposed by TURN, but that we did not want to take unilateral action on the jurisdictional allocation issue without consulting with the other states in Pacific's service territory.

The record in this proceeding strengthens our conclusion that the existing cost allocation methodology is in need of change. The existing integrated system method was adopted in a time of declining utility costs, when excessive growth in demand was promoted rather than avoided. Since that time, rapidly increasing energy costs have made the efficient use of energy resources a paramount policy objective for the nation. The greater use of marginal cost principles in allocating costs and designing rates in recent years has allowed this policy objective to be furthered. Indeed, this was a primary reason for Congressional direction, in the Public Utilities Regulatory Policy Act of 1978, to the states to consider marginal cost principles in their cost-of-service ratemaking.

As Pacific's witness Kahn pointed out, the present method is not consistent with economic principles and efficient resource use, except possibly "by accident." After an initial jurisdictional allocation is made, states can seek to subdivide their portion as best they can to develop rates that promote efficient resource use. But as both Kahn and TURN witness Wells agreed, the initial allocation, in determining overall rate levels within individual states, contributes in an important way to the degree to which efficient resource use and conservation is encouraged across the utility's system. If the existing system does not allocate costs in a manner consistent with economic principles, then efficient resource use will not be enhanced and the efficacy of individual states' efforts to avoid excessive system costs will be lessened.

Even if embedded costs were taken as the proper guide to cost-of-service ratemaking, the present method would be inadequate in our view. As staff witness Han pointed out, the present method errs by allocating all of the company's substantial baseload capacity costs according to winter peak demand responsibility. This is done even though, as Pacific witness Sirvaitis clearly indicated, that such facilities are built for energy and not to meet peak load or reliability needs. In this way, even within an embedded cost philosophy, the present method incorrectly assigns cost responsibility and thus discriminates unfairly against relatively lower load factor jurisdictions in Pacific's system, such as California, Oregon, Montana and Washington.

The time is ripe for the consideration of a new jurisdictional cost allocation methodology which is fairer and more clearly consistent with economic principles. In D.92411 we stated that we did not wish to take action on the allocation methodology without first consulting with other states. We regret to say that such consultation has not been carried out to date. While we consider cost allocation, like rate of return and other ratemaking issues, to ultimately be a matter of individual state authority it is clearly preferable to achieve a multi-state consensus on cost allocation procedures.

In this decision we do not grant to Pacific any portion of its proposed rate increase that is disputed by the parties on the basis of differing jurisdictional allocation methods. Instead, we will leave open this proceeding on the issue of jurisdictional cost allocation and incorporate the relevant portions of the record from the present phase of the proceeding into the further hearings. Other states and interested parties will be invited to participate. We will arrange for the reproduction of relevant portions of the record to be made available at our expense to any of our sister states that request such information. We also note the availability of Western

Conference of Public Service Commission's financing to facilitate the participation of other states. We thereby hope to develop a record that incorporates the views of the various states in which Pacific operates.

After our final decision on the allocation method as it relates to Pacific's California customers, we will order Pacific to revise its rates upward or downward to reflect the adopted method.

Cost allocation is a technical and complex issue for regulators, but is nevertheless quite important in ultimately simple dollars and cents terms to the multitude of ratepayers who face the monthly bill. We believe the central principle here is that costs should be allocated in proportion to the responsibility for their occurrence. Further, cost responsibility should be defined in forward looking economic cost terms, as is the case in unregulated markets, rather than in backward looking accounting terms. In D.92411 (p. 30) we stated that we saw merit in the growth shares method as an alternative to the present method because it linked increases in demand to incremental costs incurred to meet this demand. We also noted certain disadvantages associated with the procedure, such as the simplified connection between demand increases in one year and new capacity costs in the same year. Further disadvantages were noted in this proceeding, as in Kahn's assertion that growth shares assigns incremental cost responsibility in an unequal way.

Cost allocation is necessarily an inexact science. The regulator's choice is among imperfect alternatives. In addition to the current methodology, the relative use method, and the growth shares procedure, we invite parties involved in the further hearings to consider the long-run incremental cost (LRIC) method that is now used for intrastate allocations by Oregon and California, as well as other methodologies which parties deem worthy of possible adoption. To allow for the analysis of the LRIC alternative, we will order Pacific to prepare a systemwide LRIC study as a basis for jurisdictional cost allocation prior to the further hearings.

Revenue Estimates

Pacific and staff used somewhat different approaches for projecting sales estimates for the test year 1982. However, despite the differences in approach the results were sufficiently close to allow the staff to accept Pacific's projections for all categories except commercial and street and highway lighting.

For commercial sales Pacific based its projections on econometric models, whereas the staff relied on an analysis of historical trends. Staff projects 1982 sales at a level slightly lower than recorded 1980 and at about the same level as 1979; Pacific predicts sales that fall well below those recorded for 1979 and 1980.

For street and highway lighting estimates Pacific also relied on economic variables as they affected econometric models it uses for projections. The staff, on the other hand, looked to the record of sales for 20 years to develop its projections. Based on trends it observed, staff's projection was about 10% higher than Pacific's.

Although Pacific does not challenge the staff's approach to estimating sales, it does challenge the staff's concurrent use of Pacific's system load projections and the amount of power it can produce. Pacific claims that because staff accepted Pacific's estimated total production capability the megawatt-hours added to California's requirements based on the staff's commercial sales should result in a reduction of special sales allocated to California by the same number of megawatt-hours. Otherwise, an increase in plant expense must be allocated to California and the staff must find additional megawatt-hours for sales in California above the total production capability of the system. With no offsetting reduction to special sales, an appropriate adjustment to recognize the expense associated with such sales should be made, thus increasing the rate base and fuel expense allocated to California.

Staff claims that Pacific's sole argument is that staff's higher estimate of commercial sales requires a corresponding reduction for special sales on a kWh-for-kWh basis. This would be done without regard to the time of day or season of commercial consumption, the expected market for special sales, or the size of Pacific's reserve margin. Staff claims that a 1% alteration in projections which involves less than 4% of Pacific's system should not change the amount of expenses allocated to California to any significant degree. We agree with the staff and will adopt its estimates for operating revenues.

Operating Expenses

Pacific accepts the staff estimates for operating expenses with the exception of an adjustment for purchases made by Pacific from Bridger, a company two-thirds owned by Pacific. Staff's position is that the price paid for coal is not an arm's-length deal and therefore the price used for ratemaking should be adjusted so that the return on Pacific's indirect investment in Bridger will not exceed the rate of return on rate base authorized Pacific. Pacific's estimate for the price of Bridger coal for 1982 was $16.042 per ton, whereas the staff recommends a price of $12.729 per ton. This would reduce by $539,000 the fuel expense allocated to California. Staff's adjustment would also reduce fuel inventory allowance by $59,000.

The ratemaking problems posed by a utility dealing with a subsidiary that is primarily owned or wholly owned by the utility has long been recognized by this Commission and the California Supreme Court. The Commission made a similar adjustment in D.92411 (mimeo pp. 41-42) and we will again adopt the adjustments proposed by the staff.

Rate Base

Differences between rate base estimates of Pacific and the staff centered on three areas: miscellaneous surveys and investigations, removal of overburden for coal operations, and working cash allowance.

Staff proposed excluding from rate base several items totaling $342,000 in the categories of preliminary surveys and investigations and miscellaneous work in progress. The proposed exclusions are for projects that had not attained the used and useful standards for closing expenditures to plant or items that staff believes should be expensed. Of the $342,000, $60,975 was for products and studies that would not be completed during the test year 1982. About half of these expenditures are connected with Pacific's effort to renew its license for the Merlin hydroelectric project. Because Pacific's authority to operate the Merlin plant in the future is in question, staff believes capitalized expenditures for relicensing are in

the nature of construction work in progress and should not be added to rate base until Pacific starts operation under its renewed license. Staff reasons that if these expenditures are allowed in rate base, and Pacific is subsequently denied its license to operate the plant, ratepayers would be paying for a plant which would be of no use to them.

Pacific included in rate base expenses connected with long-term development of a materials management system, a computer accounting system, and a forecast model. Again staff claims these studies will not provide any benefits to ratepayers until they are completed, and because they will not be completed in the test year, staff recommends that the expense should be excluded from rate base until they are completed. The remaining adjustments proposed by staff relate to expenditures the staff claims should be properly treated as either expenses or work in progress.

Pacific claims its Merlin hydroelectric license has indeed expired, but, by attempting to attain licensing of the project, Pacific retains the right to receive relatively low-cost energy from the project during the relicensing period. Pacific claims the computer model will produce benefits over a long period of time and therefore should be included in rate base.

In the operation of the coal mines which supply fuel to Pacific's thermal generation plant at Centralia, Washington, Pacific makes expenditures for removal of the soil and other material which overlie the coal seam. Pacific's approach is to amortize the cost of this overburden removal and to include the unamortized portion in rate base. Staff claims that because overburden expenses are inextricably connected to the mining of the coal, they should not be paid by the ratepayers until the coal is actually used. Also, if the unamortized portion of the expenses are included in rate base, ratepayers are paying an additional amount to maintain a rate of return on rate base. The staff proposal ties the recovery of the overburden expenses more closely to their contribution to the generation of electricity by expensing the overburden removal cost as part of the coal cost.

It appears that for its adjustment of $342,000 the staff applies the principle that items included in rate base should be useful in providing electric service to customers. Staff claims it does not seek to deny Pacific recovery of its expenses, rather, staff proposes an accounting treatment that is fair for Pacific and its ratepayers. Staff's adjustments are reasonable and should be adopted.

Pacific included in rate base $1,002,000 for working cash and the staff $1,694,000. Pacific based its estimate on 1980 expenses; the staff not only used a difference in approach but used information updated to a later period which reflected increased expense levels. Staff believes the results of its study should be used so that Pacific is treated in the same fashion as other electric utilities subject to the Commission's jurisdiction. In A.58605, the staff also performed a working cash analysis that resulted in a figure exceeding Pacific's estimate (D.92411, mimeo. p. 38). In that proceeding, however, the staff recommended no adjustment to Pacific's estimate. In this case the staff is making a recommendation which follows the method the Commission has indicated it wants employed in determining the working cash requirement for electric utilities subject to its regulation. In addition, the staff has made its estimate based on California operations whereas Pacific made its estimate based on system operations with an allocation to California. In fairness, we cannot accept all of the staff estimates which tend to improve Pacific's results of operations and reject those that do not. In this case, the staff approach is fair and reasonable and its working cash allowance will be adopted.

Rate of Return

Table 1 is a summary of the rate of return recommendations of Pacific and the staff.

TABLE 1

Pacific Power & Light Company

Estimated and Adopted Rates of Return
Test Year 1982

Component	Capital Ratio	Cost	Weighted Cost
Pacific			
Long-Term Debt	54%	9.88%	5.34%
Preferred Stock	10	10.02	1.00
Common Equity	36	16.25	5.85
Total	100%		12.19%*
Staff			
Long-Term Debt	54%	9.17%	5.24%
Preferred Stock	10	9.94	.99
Common Equity	36	15.50**	5.58
Total	100%		11.81%
Adopted			
Long-Term Debt	54%	9.87%	5.33%
Preferred Stock	10	9.94	.99
Common Equity	36	16.00	5.76
Total	100%		12.08%

* This represents an update of the original request by Pacific of 12.05%. Pacific did not amend its revenue request, however.

** Staff also showed estimates for common equity at 15.25% and 15.75%. This produced overall returns of 11.72% and 11.90%, respectively.

Pacific, as it did in A.58605, based its estimated return on a mathematical model. The staff based its recommendation on a study of Pacific's operating results compared to other utilities having generally the same business and financial risks. In D.92411, A.58605, at mimeo. 42-47, we included a comprehensive analysis of the methods employed by Pacific and the staff. In that discussion we noted the model used by Pacific is very sensitive to the value chosen for the market capitalization rate. We questioned the objectivity of Pacific in using a formula which depends on a perhaps less-than-objective selection of a single factor. We also criticized the staff approach and see no need to repeat the criticism here.

One item of change was that Pacific used end of test year estimates for debt and preferred stock elements for its cost of capital recommendation. Pacific's witness admitted that his approach overstates the actual cost to Pacific for the test year and that the staff's treatment was a reasonable one, that is, a mid-year average cost of capital for 1982. When Pacific's estimates were recalculated to employ average capital costs for 1982, the resulting figure of 11.93% was within the range recommended by staff, that is 11.72 to 11.90%.

As is usual in rate of return recommendations, the primary difference in the recommendations had to do with return on equity. In this case, Pacific recommends 16.25% and the staff, if averaged, recommends 15.50%.

Both the witnesses for Pacific and the staff agreed that the long-term capital structure objective of Pacific of 54% long-term debt, 10% preferred equity, and 36% common equity should be used. However, the witnesses differed on the cost factors applicable to the components of the capital structure. It appears that both Pacific and the staff witnesses made relatively low estimates of the costs of projected debt issues. For instance, the staff witness estimated that future issues of debt would be at about 16%, whereas the latest included in this record came through at an effective cost of 18.6%.

There was also an issue of whether or not Pacific would issue an additional $175,000,000 worth of debt in 1981. The staff witness, in the preparation of his first exhibit, estimated that $175,000,000 would be issued at 16%. As things developed during the proceedings $100,000,000 of that was actually issued at 18.6%. The staff witness then eliminated in a revised exhibit the remaining $75,000,000 from his estimate.

Pacific claims that it will issue the $75,000,000 during 1981 or 1982 and therefore, it should be put back into the staff exhibit. It appears reasonable to put the entire $75,000,000 in for 1982 at 16%. Staff Exhibit 42 shows the charge for $175,000,000 to be $28,000,000. We will use 75/175 x $28,000,000 or $12,000,000. Exhibit 43 by staff shows average net proceeds and annual charge for 1982 as $1,446,069,000 and $140,450,000, respectively. This produces the 9.71% cost shown on Table 1. If one-half of $75,000,000 and $12,000,000 are added to the $1,446,069 and $140,450,000, respectively, the results are $1,483,569,000 and $146,450,000 which produces an average cost of 9.87%, which we will use for cost of long-term debt.

The last major decision issued by the Commission for a utility furnishing electric service was Pacific Gas and Electric Company (PG&E), D-93887 in A.60153 dated December 30, 1981, which provided PG&E 16% return on equity. We also believe that is reasonable for Pacific and will grant Pacific 16% on equity. The resulting overall return is 12.08% as shown on Table 1.

Results of Operations

Before adopting a results of operations, two issues require discussion and disposition, ITC and the effects of ERTA.

One of the most controversial issues during the proceeding was the difference between Pacific's estimate of $2,653,000 for ITC versus the staff's estimate of $749,000. Even though the staff made several adjustments to Pacific's revenues, expenses, rate base, and rate of return estimates, the lower staff estimate of ITC resulted in the staff showing Pacific requiring a larger rate increase than it had applied for. Because any ITC figures are subject to net-to-gross multiplier, the gross revenue impact of the staff's adjustment amounted to almost a $4,000,000 increase in Pacific's test year revenue requirement under proposed rates. The staff claimed its recommendation was based on previous Commission decisions on the treatment of ITC. However, at the request of the ALJ the staff reviewed these so-called pertinent decisions and could not find any in which the full Commission expressly addressed and supported the position taken by the staff. All it could find was two concurring opinions in D.84568 dated June 17, 1975 involving a case in which the Commission was considering the effects on ratemaking of the provisions of the Tax Reduction Act of 1975 including a provision which permitted a utility a choice of treatments of ITC. Because the Commission could not agree, it discontinued its case on the Tax Reduction Act, but in concurring opinions three Commissioners expressed a preference for the full flow-through approach. Staff's recommendation on ITC in this application reflects a one-year flow-through approach. However, it has been the Commission policy that taxes as actually paid or estimated to be paid during a rate year should be used if the flow-through method is used. In this case Pacific uses the flow-through method and the amount of ITC which is actually available to Pacific in the test year for tax purposes is the amount estimated by Pacific. Pacific claims it could not have the ITC available had it earned its authorized rate of return in the past. Had it been able to do that, it would have used the credits and they would not be available for 1982; and even though Pacific includes the $2,653,000 in its calculation it tends to agree with the staff that only $749,000 should be used because that is the amount estimated to be <u>generated</u> during 1982 rather than actually available to reduce taxes. Pacific further claims it suffers a double penalty if it is forced to bring forward and use in 1982 for ratemaking purposes tax credits which were generated from 1978 to 1981 but not used because of inadequate earnings.

The record is quite clear that on its tax returns for 1982 Pacific will have a large amount of ITC available, most of it carried forward from 1977 through 1981, and regardless of why these credits are there, they are available and can be used by Pacific to reduce its tax liability for 1982 and this should be flowed through to the ratepayers.[1/]

We turn now to the matter of ERTA. In late-filed Exhibit 54 staff provided an estimate of the additional revenue requirement for protection of Pacific's reduced tax liability under ERTA's depreciation guidelines. The relevant amount is $277,000 and is included in the gross revenue requirement used to amend Pacific's rates in this proceeding.

Based on the foregoing discussion of jurisdictional allocation, revenues, expenses, rate base, rate of return, ITC, and ERTA, Table 2 contains the results of operations that we adopt in this interim decision for the test year 1982. It is noted that the revenue requirement of $34,100,000 includes an amendment by Pacific to its original application for an additional $44,383 as a one time reimbursement for the award given to TURN by the Commission in D.93371 in A.58605 under the provisions of the Public Utility Regulatory Policy Act. This amendment is for only one year. Pacific is put on notice that one year from the effective date of this decision rates should be either decreased by $44,383 or justification made by advice letter for continuance of rates at the level authorized by this decision.

1/ The carry forwards for 1977 through 1980 are not subject to the normalization restrictions of ERTA.

TABLE 2

PACIFIC POWER & LIGHT COMPANY

Adopted Results of Operations
Test Year 1982

	Present Rates	Authorized Rates
Revenues	$26,925	$34,100
Expenses		
Production	9,303	9,303
Transmission	1,137	1,137
Distribution	1,812	1,812
Customer Acct.	747	761
Customer Services	341	341
Adm. and General	2,619	2,717
Subtotal	15,959	16,071
Book Depreciation	3,621	3,621
Taxes Other	1,499	1,499
State Tax	-	660
Federal Income Tax	-	270
Total Operating Expenses	21,079	22,121
Net Operating Revenue	5,846	11,979
Rate Base	99,181	99,181
Rate of Return	5.89%	12.08%

Note: To reflect our jurisdictional allocation decision, the adopted results are based on the growth share 1968 base year allocation, adjusted to reflect our other decisions, discussed above, on expenses, rate base, rate of return, and ERTA.

Rate Design

Again, as in other areas Pacific and the staff were the only parties to offer complete rate design proposals. Other than the general recommendation of Pacific for a percentage increase in rates and the staff recommendation of a uniform cents-per-kWh increase, other rate design areas of controversy included irrigation rates, small general service rates, residential customer charge, a minimal seasonal charge for agricultural pumping, a five-year contract provision for agricultural customers, and a small but volatile problem with something called the reactive power charge.

The proposed increase for irrigation rates produced a stormy reaction from farmers in the Yreka area. Pacific's rate design proposal would increase irrigation rates substantially and the staff's design would increase such rates even more. The main reason for the difference between the two is Pacific's recommendation of irrigation rates reflecting the overall increase and staff's recommendation of a uniform cents-per-kWh increase. Because under present rates the irrigation rate is considerably lower than the average system rate, (2.663 vs 3.451) the staff proposal results in the much higher percentage increase.

During the hearings, the result of a congressional bill known as the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act)[2/] became known. Its effect on Oregon ratepayers incensed California ratepayers, particularly the agricultural segment which competes with Oregon agriculture. One result of the act is that residential and small agricultural users in Oregon will be paying 20% less for their power than they would ordinarily.

The average cents per kWh in Oregon without the Northwest Power Act reduction and with the rates proposed by Pacific for 1982 would be 3.80 cents per kWh compared to the proposal in California of 4.83 cents. The following table shows the system average cents per kWh at proposed rates for 1982 for the various states served by Pacific without the Northwest Power Act reduction.

	¢/kWh
California	4.83
Montana	4.26
Oregon	3.80
Washington	3.27
Wyoming	3.02
Idaho	2.90

2/ SB 5 - Public Law 96-501, 96th Congress; 16 USC 839 et seq. Dec. 5, 1980.

If we reduce the Oregon proposed rate of 3.80 cents by 20%, the result is 3.04 cents per kWh. As will be noted in the concluding paragraph of this section, irrigation rates will be set at 3.572¢/kWh, the residential lifeline rate. This will result in an irrigation rate increase of 34.1%. We know this is contrary to the staff recommendation that where no long-run incremental cost information is available, rates should be increased by the average increase in cents per kWh. Staff's recommendation is based on the policy goal of improving efficient use of energy by approaching marginal cost pricing in the absence of long-run incremental cost studies. In this particular case, however, we must recognize the competitive aspects between Oregon and California agriculture and make allowances for them.

Staff recommends a substantial reduction in Pacific's proposed rates to small general service customers because it believes Pacific has included too much for distribution costs to serve such customers. Staff asserts that for Pacific's convenience it installs oversized distribution systems for the small demand customers. Staff maintains this oversizing, and thus overinvesting, is without economic justification. Therefore, it reduced its estimate of distribution costs for small general service customers to the costs for the next larger service which is between 15 and 30 kW.

Pacific maintains there are two reasons supporting its proposed rates. First, the needs of such small customers require a transformer which is not commercially available below a certain minimum size. Thus, of necessity, the transformer capacity installed to serve the smallest customers will be greater than the customers actually use. Second, the needs of small general service customers can be expected to vary more than residential customers. A given small general service customer at a specific location may initially require a relatively small transformer. However, if Pacific installs a small transformer and the customer's load increases unexpectedly or is replaced by another customer requiring a larger transformer, Pacific incurs the additional cost of removing the small transformer and installing the larger.

Staff claims Pacific has provided no study indicating it is cheaper initially to install an oversized transformer than to replace it. Because the transformers are investments subject to a rate of return any overinvestment would require higher revenues and be to Pacific's benefit.

We believe Pacific's position reflects a reasonable managerial decision; the size and amount of distribution facilities and resulting rates should be accepted.

TURN proposed that the residential customer service charge of $2 be eliminated. The recovery of the lost revenues would be through an increase in the energy charge. Pacific claims that the customer charge which was instituted in the last general rate case (D.92411) should be continued because it gives customers a clear price signal that expenses are incurred in providing their service facilities, reading their meters, and rendering bills. TURN believes that fixed charges such as the customer charge discourage conservation by holding down the kWh rates. As a result, the savings that a customer receives by conserving energy is smaller than it would be otherwise.

In line with the conservation principles noted by TURN, we think it is appropriate to eliminate the $2 service charge, replace it with a $2 minimum charge, and recover the lost revenue through an overall cents per kWh increase on residential rates. Also, we will maintain the 50% differential between lifeline and nonlifeline rates in the residential class. In addition, we believe setting the residential class at the average system rate as we did in D.92411 is appropriate.

Pacific proposes a five-year contract for irrigation customers using the PA-20 (irrigation) tariff. A customer would sign a written contract having a term of not less than five years. Pacific believes five years is the time period required to justify adding facilities for agricultural customers. Pacific's economic justification for this proposal, however, was very weak. After much cross-examination, Pacific eventually submitted Exhibit 31 which allegedly supported a contract term of five years. Pacific claimed that 30 inactive irrigation accounts currently exist and an additional 30 with little or no usage could become inactive. However, all of the 30 inactive customers could have become inactive after having been active for a number of years and could have paid for costs of installation many times over. Pacific also produced late-filed Exhibit 51 which showed that during 1979, there were 50 inactive Schedule PA-20 accounts that discontinued service within five years of commencing service and that an additional 73 accounts were inactive at the end of 1979 that had commenced service prior to 1974.

Pacific provided no evidence to show what its added costs are nor why a five-year contract period would ensure recovery of costs. We can see no reason to institute such a program absent a better showing on the part of Pacific.

The matter of a reactive power charge became an item of controversy in spite of the fact that it appears to involve only about $168 in yearly revenues. Although the mathematical calculation of the charges is quite simple, the language describing the charge that would be assessed is very confusing. Both the rate design witnesses for Pacific and the staff stated it is necessary to have a "kvarh" meter and a reading from such a meter before a reactive power charge can be assessed against a PA-20 customer. There is no evidence of what tariff provision would cover such a meter. We will deny Pacific's request and invite Pacific to put in more substantial evidence in its next rate case.

In summary, the adopted rate design sets the residential total equal to the average system cents per kWh, residential nonlifeline 50% above lifeline, large accounts and irrigation at the residential lifeline rate, USBR and streetlighting at the system average increase, with the residual revenue requirement to other commercial and industrial. Table 3 shows rates reflecting the above considerations applied to the required revenue shown on Table 2.

TABLE 3

Pacific Power & Light Company

Rates Under Adopted Revenues
Authorized Rates
1982

Class	Sales kWh '000	Revenue $000 Present Rates	Revenue $000 Auth. Rates	c/kWh	Increase Percent	Increase ¢/kWh
Lifeline	201,863	$ 5,660	$ 7,211	3.572	27.4	0.77
Nonlifeline	167,294	7,133	8,965	5.359	25.7	1.10
Residential Total	369,157	12,793	16,176	4.382	26.4	0.92
Com. & Ind.						
Large Accts.	63,328	1,722	2,262	3.572	31.4	0.85
Irrigation	94,258	2,510	3,367	3.572	34.1	0.91
USBR	24,539	274	348	1.418	27.0	0.30
Other Com. & Ind.	215,542	9,092	11,353	5.267	24.9	1.05
Streetlighting	4,291	221	281	6.549	27.1	1.40
Total	771,115	26,612	33,787	4.382	27.0	0.93
Temp. Service Charge		27	27			
Ret. Check Charge		2	2			
Total		26,641	33,816			
Other Oper. Rev.		284	284			
Total		26,925	34,100			

Conservation Programs

Staff made several recommendations concerning Pacific's energy conservation programs. Pacific does not contest most of them. The effect of the recommendations is to reduce Pacific's customer service and information expenses for the test year to $341,000 through adjustments of $48,000. The adjustments involve a reduction of $24,000 for agricultural pump testing expenses, $9,000 for business energy audits, and $15,000 for a proposed cash rebate incentive program unless Pacific files a complete explanation and justification for the expense.

In addition to its recommendation that Pacific's expenses for conservation activity be reduced staff suggests a system of rewards and penalties be instituted for Pacific's level of conservation achievements. If the Commission adopts such a system Pacific wants an opportunity to explain any failure to meet preset goals prior to suffering any penalties. The record shows there is a shortage of qualified contractors in Pacific's service area and therefore even if Pacific makes all reasonable efforts to achieve convservation goals the contractor shortage may hamper its progress. Also, staff acknowledged that consumers, despite the benefits of conservation, may arbitrarily reject participation in the programs. During the present period of unusually high interest rates and chaotic economic conditions, particularly in the Crescent City area, consumers may be relatively unwilling to commit to the expense of conservation programs.

We will accept the staff recommendation concerning Pacific's conservation expenses but hold any rewards or penalties system over until Pacific's next general rate case.

The other recommendations made by the Conservation staff were that Pacific should:

1. Provide staff with a copy of its updated estimate of Home Energy Audit savings studies as soon as it is available.

2. Provide staff with its memoranda report on ZIP weatherization progress and plans for meeting the cost and activity goals estimated in the 1982 workpapers.

3. Monitor the relative response rate of Home Energy Audit customers who voluntarily submit their names to be given as leads to contractors versus those who do not.

4. Provide as soon as possible the following as called for by staff in 1981:

   a. Three CVR Phase II studies.

   b. An experiment with Phase I adjustment on feeders not presently planned for conversion and a schedule for such tests.

   c. A proposal for a low-income direct weatherization program as discussed in Exhibit 41.

The above recommendations are reasonable and will be adopted. However, the three CVR Phase II studies were submitted to the Commission on November 2, 1981. Therefore, 4a. above is unnecessary.

<u>Attrition Allowance - 1983</u>

Pacific requests authorization for an increase to become effective January 1, 1983 to compensate for attrition. Under Pacific's proposal, there would be a 6.5% rate increase on January 1, 1983 producing additional annual revenues of $2,451,000. Pacific claims that even though it is not on the Regulatory Lag Plan it would like to be on a cycle of filing general rate cases every other year. If an attrition allowance is provided in this proceeding, Pacific would not anticipate filing for a general rate increase until 1983 to become effective in 1984. Pacific points out that it is different from other California utilities because it does not have automatic or semiautomatic adjustment clauses designed to pass through to ratepayers between general rate cases the impact of increases or decreases in certain costs.

In addition to the attrition allowance Pacific proposes a somewhat complicated method which it believes will protect both ratepayers and shareholders from significant changes in costs outside the normal general rate case proceedings. For instance, Pacific proposes that for 1982, the first year the proposed rates will be in effect, Pacific will pass through increases or decreases only if they are related to government-mandated changes or major changes clearly beyond Pacific's control. Such increases or decreases will be passed through only if the total revenue requirement associated with them is equal to or greater than $500,000. Further, Pacific would be required to demonstrate that the increase would not improve its actual return on equity and that its achieved return would not exceed the allowed return. All such adjustments would be on a prospective basis. For 1983 Pacific proposes a different method. It would not request a rate increase or decrease in 1983 unless it experiences a 50 basis point decrease or a 25 basis point increase in the then prevailing rate of return as adjusted. Adjustments to the rate of return would be allowed only if fixed charges as actually incurred differed from those estimated. If Pacific overachieves at a level of 25 basis points greater than the allowed return, it would be required to file a rate decrease to bring the rate of return down to the ordered rate of return. If the rate of return is 50 basis points below that allowed, Pacific could file for a rate increase. However, such an increase would only be sufficient to bring the company up to the allowed rate of return less 25 basis points. Therefore, even after the increase, Pacific would only be allowed to earn less than the amount found reasonable. Pacific claims the proposal would not provide a guaranteed rate of return nor inhibit managerial incentive to provide service on a least-cost basis.

TURN opposes in principle the policy of granting utility rate increases more than a year in advance on the basis of inflation that may or may not occur. TURN claims that granting an attrition allowance does not in any way guarantee ratepayers that further increases will not be requested and granted and cites D.92656 in PG&E's A.59902. TURN believes an attrition allowance tends to become a self-fulfilling prophecy. TURN suggests that should the Commission consider granting both an attrition allowance and a mechanism to handle specific major cost offsets, it should define major more strictly than Pacific has proposed and suggested $2,000,000 or 200 basis points as benchmarks.

It appears that what Pacific is requesting is far more complex than the situation deserves. Further, we do not share the apparent aim of the proposal to fully insulate the company from all cost changes in such a way that a risk-free, cost-plus operating environment is created.

Instead, we invite Pacific to file a 1983 attrition allowance patterned after those authorized for PG&E and San Diego Gas & Electric Company in D.93887 and D.93892. This attrition allowance should be based on the results of operations for the 1982 test year adopted in this decision and should take into account any modifications of the 1982 results that arise from the final cost allocation decision discussed above.

Other Staff Recommendations

Staff made several recommendations not directly contested by Pacific. Staff requests the Commission include the following recommendations in its order:

1. In its next general rate application Pacific should perform a longrun incremental cost study for agricultural customers (PA-20) and for agricultural pumping service provided to the US Bureau of Reclamation. Staff believes this information is crucial to the equitable distribution of rate increases among classes of customers.

2. Pacific should carry out a program of converting outdoor mercury vapor lamps of 21,000 and 55,000 lumens to high-pressure sodium lamps over the next two years. Pacific should continue to monitor the economics of converting 7,000 lumen mercury vapor lamps to high-pressure sodium lamps and should begin a conversion program for these lamps when they become economically justified.

3. Schedule LS-52 covering company-owned special street and highway lighting services and Schedule LS-53 for privately owned special street and highway lighting service should be revised to eliminate the appearance that company-owned service receives a lower energy rate than comparable privately owned service.

4. To improve energy efficiency in street and outdoor lighting Pacific should provide customers information on the energy use expressed in kWh for each light covered under the street and outdoor lighting schedules.

5. The elimination of the declining block rates for Pacific's tariffs should be expanded to include Schedule A-32.

Findings of Fact

1. By this application Pacific requests increases in its electric service revenues for its California customers in the amount of $10,347,000 or 36% over revenues under present rates based on the test year 1982.

2. Public hearings in this application were held during 1981 at which all interested parties had an opportunity to be heard.

3. Pacific also requests an increase to become effective January 1, 1983 to compensate for attrition.

4. Pacific requires additional gross revenue of $277,000 over what the Commission would otherwise grant in this decision so the order which follows will preserve Pacific's eligibility for the benefits of ERTA.

5. Further hearings on the jurisdictional cost allocation issue are necessary.

6. Portions of Pacific's rate request that are disputed on the basis of differing jurisdictional allocation methods should be the subject of final Commission decision after the further hearings.

7. The sales, revenue, expense, and rate base estimates of the staff for the test year 1982 are reasonable.

8. The revenue requirement for test year 1982 includes $44,383 to cover Pacific's payment to TURN for TURN's PURPA participation in A.58605.

9. The investment tax credit as calculated by Pacific for income tax purposes is reasonable.

10. An overall rate of return of 12.08% which includes a return on equity of 16% is reasonable.

11. The results of operations shown on Table 2 are reasonable for the test year 1982 and will produce a revenue requirement for Pacific of $34,100,000.

12. The rate design shown on Table 5 is reasonable and will produce the additional revenue requirement of $7,175,000 for the test year 1982.

13. Pacific's proposal for irrigation customers to sign up for a five-year contract before service would be provided is unreasonable.

14. Pacific's proposal concerning a reactive power charge is unreasonable.

15. The staff's recommendations on conservation measures with the exception of the penalty provision proposed in Exhibit 41 are reasonable and will be adopted.

16. Pacific's proposal for an attrition allowance procedure for 1982 and 1983 is unreasonable.

17. Other staff recommendations contained in staff exhibits and noted in this decision are reasonable and will be adopted.

18. 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.

19. Because the rate year on which the increases authorized is underway there is an immediate need for rate relief.

Conclusion of Law

Based on the foregoing findings of fact and under PU Code § 454 the Commission may grant Pacific authority to increase rates as provided for in the following order to enable Pacific to earn additional annual revenues of $7,175,000.

INTERIM ORDER

IT IS ORDERED that:

1. After the effective date of this order Pacific Power & Light Company (Pacific) is authorized to file revised rate schedules reflecting the rates and rate increases set forth in Appendix A to this decision and concurrently withdraw and cancel its presently effective schedules. Such filing shall comply with General Order 96-A.

2. The effective date of the revised schedules authorized by Ordering Paragraph 1 shall be 4 days after the date of filing. The revised schedules shall apply only to service rendered on and after the effective date of the revised schedules.

3. Within 60 days after the effective date of this order Pacific shall provide staff with:

a. A copy of Pacific's updated estimate of Home Energy Audit savings studies.

b. A memoranda report on ZIP weatherzation progress and plans for meeting the cost and activity goals in Pacific's 1982 workpapers.

c. A proposed experiment with the Phase I adjustment on feeders not presently planned for conversion and a schedule for tests.

d. A proposal for a low-income direct weatherization program as discussed in Exhibit 41.

4. For its next general rate application Pacific shall perform a longrun incremental cost study for agricultural customers (PA-20) and agricultural pumping service provided to the US Bureau of Reclamation.

5. Pacific shall carry out a program of converting outdoor mercury vapor lamps of 21,000 and 55,000 lumens to high-pressure sodium lamps over the next two years.

6. Pacific shall continue to monitor the economics of converting 7,000 lumen mercury vapor lamps to high-pressure sodium lamps and should begin a conversion program for these lamps when they become economically justified.

7. Pacific shall monitor the relative response rate of home energy audit customers who voluntarily submit their names to be given as leads to contractors versus those who do not.

8. Pacific shall provide customers information on the energy use expressed in kilowatt-hours for each light covered under the street and outdoor lighting schedules.

9. Within 60 days from the effective date of this decision Pacific shall submit a systemwide long-run incremental cost study. The study should be suitable for jurisdictional cost allocation, based on the number and type of customers in each jurisdiction and their timing and level of demand. Jurisdictional LRIC percentages should be derived for use in allocating the revenue requirement. Pacific shall serve this study upon the chairpersons of the relevant state regulatory commissions within its service territory.

10. The Executive Director shall make available to other state commissions reproductions of portions of the record in this proceeding relevant to jursidictional allocation at their request.

11. Hearings on jurisdictional allocations should be held within 90 days of the effective date of this decision.

12. Within 90 days from the effective date of this decision Pacific shall file by the advice letter procedure proposals for revising its tariffs to eliminate:

a. The appearance that company-owned service receives a lower energy rate than comparable privately owned service covered by Tariff Schedules LS-52 and LS-53.

b. The delcining block rates in Tariff Schedule A-32.

13. One year from the date tariff changes authorized by this decision are effective Pacific shall decrease its rates on an equal cents-per kWh basis so that overall annual revenues are reduced by $44,383.

14. During the next billing period Pacific shall send to all its customers, as a bill insert, the notice shown in Appendix B.

15. In all other respects A.60560 is denied.

This order is effective today.

Dated May 4, 1982, at San Francisco, California.

RICHARD D. GRAVELLE
LEONARD M. GRIMES, JR.
VICTOR CALVO
PRISCILLA C. GREW
Commissioners

I dissent. I would adopt Administrative Law Judge Porter's decision.

/s/ JOHN E. BRYSON
Commissioner

I CERTIFY THAT THIS DECISION WAS APPROVED BY THE ABOVE COMMISSIONERS TODAY.

Joseph E. Bodovitz, Executive Director

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Schedule No. A-32
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 C
to, or in standby for customer's electric generation or other energy C
sources.

TERRITORY

Within the entire territory served in California by the Utility.

NET MONTHLY RATE T

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

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.
$.62 per kw for each kw of of Billing Demand in excess of 100 kw.

Energy Charge:

5.988¢ per kwh for the first 6,000 kwh plus 75 kwh per kw I
for each kw of Billing Demand in excess of 20 kw.
4.158¢ per kwh for all additional kwh. I

(Continued)

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APPENDIX A
Page 2

Schedule No. A-36

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. C C

TERRITORY

Within the entire territory served in California by the Utility.

NET MONTHLY RATE

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

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:

2.953¢ per kwh for all kwh. I

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) D

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Schedule No. AT-48

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

Energy Charge:
2.747¢ per kwh for all kwh I

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. R I

DELIVERY AND METERING VOLTAGE ADJUSTMENTS

The above monthly charges are applicable without adjustment for voltage when delivery and metering are at Company's standard secondary distribution voltage.

Metering: For so long as metering voltage is at Company's available primary distribution voltage of 11 kv or greater, the above charges will be reduced by 1.5%. T

Delivery: For so long as delivery voltage is at Company'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. T

When a new delivery or an increase in capacity for an existing delivery is at request of customer, made by means of Company-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. N N

(Continued) L D

Issued by

Advice Letter No. ______ Date Filed ______

Decision No. ______ TITLE Effective ______

Resolution No. ______

Schedule No. AWH-31

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.

NET MONTHLY RATE

The Net Monthly Rate shall be the sum of the Basic and Energy Charges. T N

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

Energy Charge:

2.877¢ per kwh for all kwh I

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) D

Schedule No. D

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 lifeline allowance will apply unless lifeline allowances available for electric space heating and/or electric water heating are qualified and elected.

TERRITORY

Within the entire territory served in California by the Utility.

NET MONTHLY RATE

The Net Monthly Rate shall be the greater of the Energy Charges or the Minimum Charge. T N N

RATES

Energy Charge:

	Per Month Lifeline Rates	Per Month Non-Lifeline Rates
All kwh per kwh	3.567¢	5.365¢ I

Minimum Charge:

$2.00 C

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. L

(Continued) D

SCHEDULE NO. DM-9

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 lifeline allowance will apply unless lifeline allowances available for electric space heating and/or electric water heating are qualified and elected.

TERRITORY

Within the entire territory served in California by the Utility.

NET MONTHLY RATE

The Net Monthly Rate 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)

Schedule No. DS-8

MULTI-FAMILY RESIDENDIAL SERVICE - SUBMETERED

APPLICABILITY

Applicable to single-phase alternating 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 lifeline allowance will apply unless lifeline allowances available for electric space heating and/or electric water heating are qualified and elected.

TERRITORY

Within the entire territory served in California by the Utility.

NET MONTHLY RATE

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

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

MINIMUM CHARGE

The Minimum Charge shall be calculated in accordance with the applicable 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 submetered single-family dwelling units or apartments

(Continued)

Schedule No. LS-51

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.

NET MONTHLY RATE

Nominal Lumen Rating	Rate per Lamp
5,800	$5.98
22,000	9.93
50,000	18.43

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.

Schedule No. LS-52

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.

NET MONTHLY RATE

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 3.376¢ per kwhr I

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)

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Schedule No. LS-53

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.

NET MONTHLY RATE

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 3.918¢ per kwhr. I

b) Where the customer operates and maintains the system, a flat rate equal to one-twelfth the estimated annual energy cost at 3.918¢ per kwhr. I

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.

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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

Within the entire territory in California served by the Utility.

I. NET MONTHLY RATE 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	$2.98	$3.49	$5.61	$7.75	$9.99	I

Mercury Vapor Lamps

Nominal Lumen Rating	7000	21000	
Rate per Lamp - horizontal	$6.62	$11.73	I
Rate per Lamp - vertical	$6.08	$11.38	I

Street lights on metal poles:

Mercury Vapor Lamps

Nominal Lumen Rating	7000	21000	
Rate per Lamp			
Horizontal	$8.83	—	I
Horizontal		$14.47	I

B. **Underground System**

Street lights on metal poles:

Mercury Vapor Lamps

Nominal Lumen Rating	7000	21000	
Rate per Lamp			
Horizontal	—	$17.99	I
Vertical	—	$16.04	I

(Continued)

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Issued by

Advice Letter No. ______ ______ Date Filed ______
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Decision No. ______ ______ Effective ______
TITLE
Resolution No. ______

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Schedule No. LS-57

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

II. NET MONTHLY RATE 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	55000
Rate per Lamp	$7.35	$12.32	$25.68

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.

(Continued)

Issued by

Advice Letter No. — NAME — Date Filed
Decision No. — TITLE — Effective
Resolution No.

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Schedule No. LS-58

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.

NET MONTHLY RATE 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		
1,000	$ 1.45	$ 2.67	I
2,500	2.86	4.13	
4,000	4.66	5.98	
6,000	6.39	7.76	I
	MERCURY VAPOR		
7,000	$ 2.98	$ 3.72	I
21,000	6.74	7.53	
55,000	16.14	17.21	I
	FLUORESCENT		
21,400	$ 6.39	$ 8.34	I

(Continued)

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Schedule No. OL-15

OUTDOOR AREA LIGHTING 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.

NET MONTHLY RATE T

Type of Luminaire	Nominal Lamp Rating	Per Luminaire Per Month
Mercury Vapor	* 7,000 Lumens	$ 7.81
	*21,000	14.73
	*55,000	30.28
High Pressure Sodium	5,800 "	$10.68
" " "	22,000 "	15.57
" " "	50,000 "	24.67

I

*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.

Schedule No. OL-42

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. T

NET MONTHLY RATE

The Net Monthly Rate shall be the sum of the Basic and Energy N
Charges. N

Per Month

Basic Charge:

For single-phase service	$5.00
For three-phase service	$8.00

Energy Charge: I

5.675¢ 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. D

CONTINUING SERVICE N

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. N

Schedule No. PA-20

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 Company 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. C C

Meter Readings from March 27 through November 27:

Energy Charge:
3.413¢ per kwh for the first 14,000 kwh I
2.483¢ per kwh for all additional kwh I

Meter Readings from November 28 through March 26:

Demand Charge:
$1.00 per kw of monthly Billing Demand

Energy Charge:
5.163¢ per kwh for the first 100 kwh monthly per kw of monthly Billing Demand I
3.353¢ per kwh for all additional kwh I

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)

Schedule No. PA-20

AGRICULTURAL PUMPING SERVICE
(Continued)

ANNUAL CHARGE (collected in November Billing Period) (Continued)

If Load Size is:	Annual Charge is:
Three-phase service:	
50 kw* or less	$10 per kw* but not less than a Basic Charge of $72
51 to 300 kw*	$100 plus $8 per kw*
Over 300 kw*	$700 plus $6 per kw*

* 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.

BILLING DEMAND

The measured kw shown by or computed from the readings of Utility's demand meter, or by appropriate test, for the 15-minute period of customer's greatest use during the billing month, but not less than two kw; provided, however, that for motors not over 10 hp, the demand may, subject to confirmation by test, be determined from the nameplate hp rating and the following table:

2 HP or less	2 kw
From 2.1 through 3 HP	3 kw
From 3.1 through 5 HP	5 kw
From 5.1 through 7.5 HP	7 kw
From 7.6 through 10 HP	9 kw

SPECIAL CONDITIONS

1. An application of the monthly rate which includes energy in excess of 750 kwh per kw will be computed with such excess at the average price per kwh of the first 750 kwh per kw.

2. When a monthly billing computes at less than $3.00, the consumption will instead be carried forward to the succeeding month.

3. At the option of the customer, irrigation season energy charges may be prorated from March 1 through October 31, provided the customer furnishes Company with the meter readings necessary for determining such prorated billings.

(END OF APPENDIX A)

APPENDIX B

Notice

$277,000 of the recent rate increase granted to Pacific Power & Light Company was made necessary by changes in tax laws proposed by the President and passed by Congress last year. This was the Economic Recovery Tax Act of 1981. Among its provisions was a requirement that utility rate-payers be charged for certain corporate taxes even though the utility does not have to pay them. This results from the way utilities may treat tax savings from depreciation on their plant and equipment. The savings can no longer be credited to the ratepayer, but must be left with the company and its shareholders.

For a more detailed explanation of this tax change, send a stamped, self-addressed envelope to the Consumer Affairs Branch of the Public Utilities Commission, 350 McAllister Street, San Francisco, CA 94102.

(END OF APPENDIX B)

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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.

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TERRITORY

Within the entire territory served in California by the Utility.

NET MONTHLY RATE T

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

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.
$.62 per kw for each kw of of Billing Demand in excess of 100 kw.

Energy Charge:

5.988¢ per kwh for the first 6,000 kwh plus 75 kwh per kw for each kw of Billing Demand in excess of 20 kw. I
4.158¢ per kwh for all additional kwh. I

(Continued)

D

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. C C

TERRITORY

Within the entire territory served in California by the Utility.

NET MONTHLY RATE

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

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:

2.953¢ per kwh for all kwh. I

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)

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Schedule No. AT-48

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

Energy Charge:
2.747¢ per kwh for all kwh I

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. R I

DELIVERY AND METERING VOLTAGE ADJUSTMENTS

The above monthly charges are applicable without adjustment for voltage when delivery and metering are at Company's standard secondary distribution voltage.

Metering: For so long as metering voltage is at Company's available primary distribution voltage of 11 kv or greater, the above charges will be reduced by 1.5%. T

Delivery: For so long as delivery voltage is at Company'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. T

When a new delivery or an increase in capacity for an existing delivery is, at request of customer, made by means of Company-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. N N

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(Continued)

Schedule No. AWH-31

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.

NET MONTHLY RATE

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

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

Energy Charge:

2.877¢ 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)

Schedule No. D

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 lifeline allowance will apply unless lifeline allowances available for electric space heating and/or electric water heating are qualified and elected.

TERRITORY

Within the entire territory served in California by the Utility.

NET MONTHLY RATE

The Net Monthly Rate shall be the greater of the Energy Charges or the Minimum Charge.

RATES

Energy Charge:	Per Month	
	Lifeline Rates	Non-Lifeline Rates
All kwh per kwh	3.567¢	5.365¢

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)

Schedule No. LS-51

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.

NET MONTHLY RATE

Nominal Lumen Rating	Rate per Lamp
5,800	$ 5.98
22,000	9.93
50,000	18.43

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.

A.60560 /ALJ/ks *

Schedule No. LS-52

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.

NET MONTHLY RATE

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 3.376¢ 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.60560 /ALJ/ks *

Schedule No. LS-53

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.

NET MONTHLY RATE

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 3.918¢ per kwhr.

b) Where the customer operates and maintains the system, a flat rate equal to one-twelfth the estimated annual energy cost at 3.918¢ 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.

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

Within the entire territory in California served by the Utility.

I. NET MONTHLY RATE 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	$2.98	$3.49	$5.61	$7.75	$9.99	I
Mercury Vapor Lamps						
Nominal Lumen Rating				7000	21000	
Rate per Lamp - horizontal				$6.62	$11.73	I
Rate per Lamp - vertical				$6.08	$11.38	I

Street lights on metal poles:

Mercury Vapor Lamps			
Nominal Lumen Rating	7000	21000	
Rate per Lamp			
Horizontal	$8.83	—	I
Horizontal		$14.47	I

B. Underground System

Street lights on metal poles:

Mercury Vapor Lamps			
Nominal Lumen Rating	7000	21000	
Rate per Lamp			
Horizontal	—	$17.99	I
Vertical	—	$16.04	I

(Continued)

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Schedule No. LS-57

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

II. NET MONTHLY RATE 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	55000
Rate per Lamp	$7.35	$12.32	$25.68

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.

(Continued)

Schedule No. LS-58

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.

NET MONTHLY RATE 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	
1,000	$ 1.45	$ 2.67
2,500	2.86	4.13
4,000	4.66	5.98
6,000	6.39	7.76
	MERCURY VAPOR	
7,000	$ 2.98	$ 3.72
21,000	6.74	7.53
55,000	16.14	17.21
	FLUORESCENT	
21,400	$ 6.39	$ 8.34

(Continued)

Schedule No. OL-15

OUTDOOR AREA LIGHTING 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.

NET MONTHLY RATE

Type of Luminaire	Nominal Lamp Rating	Per Luminaire Per Month
Mercury Vapor	* 7,000 lumens	$ 7.81
" "	*21,000 "	14.73
" "	*55,000 "	30.28
High Pressure Sodium	5,800 "	$10.68
" " "	22,000 "	15.57
" " "	50,000 "	24.67

*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.

Schedule No. OL-42

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.

NET MONTHLY RATE

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

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

Energy Charge:
5.675¢ 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.

Schedule No. PA-20

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 Company 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 27 through November 27:

Energy Charge:
3.413¢ per kwh for the first 14,000 kwh
2.483¢ per kwh for all additional kwh

Meter Readings from November 28 through March 26:

Demand Charge:
$1.00 per kw of monthly Billing Demand

Energy Charge:
5.163¢ per kwh for the first 100 kwh monthly per kw of monthly Billing Demand
3.353¢ 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)

APPENDIX B

Notice

$277,000 of the recent rate increase granted to Pacific Power & Light Company was made necessary by changes in tax laws proposed by the President and passed by Congress last year. This was the Economic Recovery Tax Act of 1981. Among its provisions was a requirement that utility rate-payers be charged for certain corporate taxes even though the utility does not have to pay them. This results from the way utilities may treat tax savings from depreciation on their plant and equipment. The savings can no longer be credited to the ratepayer, but must be left with the company and its shareholders.

For a more detailed explanation of this tax change, send a stamped, self-addressed envelope to the Consumer Affairs Branch of the Public Utilities Commission, 350 McAllister Street, San Francisco, CA 94102.

(END OF APPENDIX B)

The results of operations adopted by the Commission reflect most of the revenue, expense, and rate base adjustments recommended by the Commission's staff. A notable exception is the staff treatment of income taxes, specifically ITC. The position of Pacific is adopted by the Commission because it reflects actual credits available for 1982, whereas the staff version reflects credits earned during 1982. The difference for this rate case is substantial, the staff method resulting in a much higher revenue requirement than requested by Pacific.

The Commission adopts an overall rate of return for 1982 of 12.08% which provides for 16% on common equity. Another factor affecting Pacific's revenue requirement is the Economic Tax Recovery Act (ERTA). The effect of ERTA is to increase the revenue requirement otherwise adopted herein by $277,000.

This decision increases the overall rates in California by $7,175,000 or 27%, applies an overall kWh increase to residential rates, and eliminates the present $2 monthly charge replacing it with a $2 minimum charge while recouping the lost revenue from an overall energy charge increase for residential users. The Commission believes this best reflects its current policies on encouraging energy conservation through use sensitive pricing.

Pacific requested the Commission to authorize an automatic attrition allowance which would increase rates on January 1, 1983. The Commission finds Pacific's attrition proposal to be unreasonable and invites Pacific to request an attrition allowance based on a methodology similar to that adopted by this Commission in its other recent electric utility rate decisions.

Issues

The following is a summary of the major issues in this proceeding in the order they will be discussed in this decision.

Allocation Procedures

In D.92411, A.58605, we included an extensive discussion of jurisdictional allocation procedures used or proposed by the parties. In that decision we indicated that we did not support the existing methodology used by Pacific, that we saw merit in the growth share alternative proposed by TURN, but that we did not want to take unilateral action on the jurisdictional allocation issue without consulting with the other states in Pacific's service territory.

The record in this proceeding strengthens our conclusion that the existing cost allocation methodology is in need of change. The existing integrated system method was adopted in a time of declining utility costs, when excessive growth in demand was promoted rather than avoided. Since that time, rapidly increasing energy costs have made the efficient use of energy resources a paramount policy objective for the nation. The greater use of marginal cost principles in allocating costs and designing rates in recent years has allowed this policy objective to be furthered. Indeed, this was a primary reason for Congressional direction, in the Public Utilities Regulatory Policy Act of 1978, to the states to consider marginal cost principles in their cost-of-service ratemaking.

As Pacific's witness Kahn pointed out, the present method is not consistent with economic principles and efficient resource use, except possibly "by accident." After an initial jurisdictional allocation is made, states can seek to subdivide their portion as best they can to develop rates that promote efficient resource use. But as both Kahn and TURN witness Wells agreed, the initial allocation, in determining overall rate levels within individual states, contributes in an important way to the degree to which efficient resource use and conservation is encouraged across the utility's system. If the existing system does not allocate costs in a manner consistent with economic principles, then efficient resource use will not be enhanced and the efficacy of individual states' efforts to avoid excessive system costs will be lessened.

For commercial sales Pacific based its projections on econometric models, whereas the staff relied on an analysis of historical trends. Staff projects 1982 sales at a level slightly lower than recorded 1980 and at about the same level as 1979; Pacific predicts sales that fall well below those recorded for 1979 and 1980.

For street and highway lighting estimates Pacific also relied on economic variables as they affected econometric models it uses for projections. The staff, on the other hand, looked to the record of sales for 20 years to develop its projections. Based on trends it observed, staff's projection was about 10% higher than Pacific's.

Although Pacific does not challenge the staff's approach to estimating sales, it does challenge the staff's concurrent use of Pacific's system load projections and the amount of power it can produce. Pacific claims that because staff accepted Pacific's estimated total production capability the megawatt-hours added to California's requirements based on the staff's commercial sales should result in a reduction of special sales allocated to California by the same number of megawatt-hours. Otherwise, an increase in plant expense must be allocated to California and the staff must find additional megawatt-hours for sales in California above the total production capability of the system. With no offsetting reduction to special sales, an appropriate adjustment to recognize the expense associated with such sales should be made, thus increasing the rate base and fuel expense allocated to California.

Staff claims that Pacific's sole argument is that staff's higher estimate of commercial sales requires a corresponding reduction for special sales on a kWh-for-kWh basis. This would be done without regard to the time of day or season of commercial consumption, the expected market for special sales, or the size of Pacific's reserve margin. Staff claims that a 1% alteration in projections which involves less than 4% of Pacific's system should not change the amount of expenses allocated to California to any significant degree. We agree with the staff and will adopt its estimates for operating revenues.

Operating Expenses

Pacific accepts the staff estimates for operating expenses with the exception of an adjustment for purchases made by Pacific from Bridger, a company two-thirds owned by Pacific. Staff's position is that the price paid for coal is not an arm's-length deal and therefore the price used for ratemaking should be adjusted so that the return on Pacific's indirect investment in Bridger will not exceed the rate of return on rate base authorized Pacific. Pacific's estimate for the price of Bridger coal for 1982 was $16.042 per ton, whereas the staff recommends a price of $12.729 per ton. This would reduce by $539,000 the fuel expense allocated to California. Staff's adjustment would also reduce fuel inventory allowance by $59,000.

The ratemaking problems posed by a utility dealing with a subsidiary that is primarily owned or wholly owned by the utility has long been recognized by this Commission and the California Supreme Court. The Commission made a similar adjustment in D.92411 (mimeo pp. 41-42) and we will again adopt the adjustments proposed by the staff.

Rate Base

Differences between rate base estimates of Pacific and the staff centered on three areas: miscellaneous surveys and investigations, removal of overburden for coal operations, and working cash allowance.

Staff proposed excluding from rate base several items totaling $342,000 in the categories of preliminary surveys and investigations and miscellaneous work in progress. The proposed exclusions are for projects that had not attained the used and useful standards for closing expenditures to plant or items that staff believes should be expensed. Of the $342,000, $60,975 was for products and studies that would not be completed during the test year 1982. About half of these expenditures are connected with Pacific's effort to renew its license for the Merlin hydroelectric project. Because Pacific's authority to operate the Merlin plant in the future is in question, staff believes capitalized expenditures for relicensing are in

the nature of construction work in progress and should not be added to rate base until Pacific starts operation under its renewed license. Staff reasons that if these expenditures are allowed in rate base, and Pacific is subsequently denied its license to operate the plant, ratepayers would be paying for a plant which would be of no use to them.

Pacific included in rate base expenses connected with long-term development of a materials management system, a computer accounting system, and a forecast model. Again staff claims these studies will not provide any benefits to ratepayers until they are completed, and because they will not be completed in the test year, staff recommends that the expense should be excluded from rate base until they are completed. The remaining adjustments proposed by staff relate to expenditures the staff claims should be properly treated as either expenses or work in progress.

Pacific claims its Merlin hydroelectric license has indeed expired, but, by attempting to attain licensing of the project, Pacific retains the right to receive relatively low-cost energy from the project during the relicensing period. Pacific claims the computer model will produce benefits over a long period of time and therefore should be included in rate base.

In the operation of the coal mines which supply fuel to Pacific's thermal generation plant at Centralia, Washington, Pacific makes expenditures for removal of the soil and other material which overlie the coal seam. Pacific's approach is to amortize the cost of this overburden removal and to include the unamortized portion in rate base. Staff claims that because overburden expenses are inextricably connected to the mining of the coal, they should not be paid by the ratepayers until the coal is actually used. Also, if the unamortized portion of the expenses are included in rate base, ratepayers are paying an additional amount to maintain a rate of return on rate base. The staff proposal ties the recovery of the overburden expenses more closely to their contribution to the generation of electricity by expensing the overburden removal cost as part of the coal cost.

TABLE 2

PACIFIC POWER & LIGHT COMPANY

Adopted Results of Operations
Test Year 1982

	Present Rates	Authorized Rates
Revenues	$26,925	$34,100
Expenses		
Production	9,303	9,303
Transmission	1,137	1,137
Distribution	1,812	1,812
Customer Acct.	747	761
Customer Services	341	341
Adm. and General	2,619	2,717
Subtotal	15,959	16,071
Book Depreciation	3,621	3,621
Taxes Other	1,499	1,499
State Tax	-	660
Federal Income Tax	-	270
Total Operating Expenses	21,079	22,121
Net Operating Revenue	5,846	11,979
Rate Base	99,181	99,181
Rate of Return	5.89%	12.08%

Note: To reflect our jurisdictional allocation decision, the adopted results are based on the growth share 1968 base year allocation, adjusted to reflect our other decisions, discussed above, on expenses, rate base, rate of return, and ERTA.

TABLE 3

Pacific Power & Light Company

Rates Under Adopted Revenues
Authorized Rates
1982

Class	Sales kWh '000	Revenue $000 Present Rates	Auth. Rates	c/kWh	Increase Percent	c/kWh
Lifeline	201,863	$ 5,660	$ 7,211	3.572	27.4	0.77
Nonlifeline	167,294	7,133	8,965	5.359	25.7	1.10
Residential Total	369,157	12,793	16,176	4.382	26.4	0.92
Com. & Ind.						
Large Accts.	63,328	1,722	2,262	3.572	31.4	0.85
Irrigation	94,258	2,510	3,367	3.572	34.1	0.91
USBR	24,539	274	348	1.418	27.0	0.30
Other Com. & Ind.	215,542	9,092	11,353	5.267	24.9	1.05
Streetlighting	4,291	221	281	6.549	27.1	1.40
Total	771,115	26,612	33,787	4.382	27.0	0.93
Temp. Service Charge		27	27			
Ret. Check Charge		2	2			
Total		26,641	33,816			
Other Oper. Rev.		284	284			
Total		26,925	34,100			

6. Pacific shall continue to monitor the economics of converting 7,000 lumen mercury vapor lamps to high-pressure sodium lamps and should begin a conversion program for these lamps when they become economically justified.

7. Pacific shall monitor the relative response rate of home energy audit customers who voluntarily submit their names to be given as leads to contractors versus those who do not.

8. Pacific shall provide customers information on the energy use expressed in kilowatt-hours for each light covered under the street and outdoor lighting schedules.

9. Within 60 days from the effective date of this decision Pacific shall submit a systemwide long-run incremental cost study. The study should be suitable for jurisdictional cost allocation, based on the number and type of customers in each jurisdiction and their timing and level of demand. Jurisdictional LRIC percentages should be derived for use in allocating the revenue requirement. Pacific shall serve this study upon the chairpersons of the relevant state regulatory commissions within its service territory.

10. The Executive Director shall make available to other state commissions reproductions of portions of the record in this proceeding relevant to jursidictional allocation at their request.

11. Hearings on jurisdictional allocations should be held within 90 days of the effective date of this decision.

12. Within 90 days from the effective date of this decision Pacific shall file by the advice letter procedure proposals for revising its tariffs to eliminate:

a. The appearance that company-owned service receives a lower energy rate than comparable privately owned service covered by Tariff Schedules LS-52 and LS-53.

b. The delcining block rates in Tariff Schedule A-32.

13. One year from the date tariff changes authorized by this decision are effective Pacific shall decrease its rates on an equal cents-per kWh basis so that overall annual revenues are reduced by $44,383.

14. During the next billing period Pacific shall send to all its customers, as a bill insert, the notice shown in Appendix B.

15. In all other respects A.60560 is denied.

This order is effective today.

Dated ______________________, at San Francisco, California.

ALJ/ks 3

Decision 82 05 042 MAY - 4 1982

ORIGINAL

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 electric service.	Application 60560 (Filed May 18, 1981, amended September 17, 1981)

Leonard A. Girard, Attorney at Law, for Pacific Power & Light Company, applicant.
Antone S. Bulich, Jr., Attorney at Law, for California Farm Bureau Federation; Michel Peter Florio, Attorney at Law, for Toward Utility Rate Normalization; Nicholas R. Tibbetts, for Assemblyman Douglas H. Bosco; interested parties.
Brian T. Cragg, Attorney at Law, for the Commission staff.

INTERIM OPINION

By this application Pacific Power & Light Company (Pacific) requests Commission approval to increase electric rates for its California service. Pacific's proposed rate schedules, together with special sales and operating revenues, would provide annual revenue of $38,839,000 during test year 1982. The increase over revenue at present rates is $10,347,000, an overall increase of 36.0% and about 39.9% on kilowatt-hour (kWh) sales. Pacific also requests an attrition allowance of $2,451,000 effective January 1, 1983. Pacific amended this application at hearing on September 17, 1981 asking for an additional increase of $44,383 paid to another party on order of the Commission. (Decision (D.) 93371 dated August 4, 1981 in Application (A.) 58605.) This was for advocacy on issues covered by Rule 76.01 of our Rules of Practice and Procedure in Pacific's last rate proceeding.

A prehearing conference was held on August 3, 1981 in San Francisco before Administrative Law Judge (ALJ) Albert C. Porter. Public hearings were held in Yreka, September 14 and 15, 1981, and in Crescent City, September 17 and 18, 1981. Further hearings were held in San Francisco, September 21-25, October 13-16, and October 22, 1981. Concurrent briefs were filed November 13, 1981 and oral replies were heard in San Francisco, November 20, 1981. On December 11, 1981 the Commission staff (staff) submitted a letter to the ALJ supplying a requested reference to the staff position concerning treatment of investment tax credit (ITC). On February 19, 1982, staff filed a motion to reopen the proceedings for receipt of a late-filed exhibit concerning the effects of the Economic Recovery Tax Act of 1981 (ERTA). That motion is granted and the exhibit is received as number 54.

This application is now ready for decision.

<u>Summary</u>

In May 1981, Pacific filed for an increase in its electric rates for consumers in Northern California. The increase requested totaled $10,347,000, an overall increase of about 36%, but about 40% for residential customers and 39% for irrigation customers. There was considerable interest and participation in hearings held on the request by Pacific's California customers particularly since Oregon customers just across the border were due for a 20% rate decrease. That decrease was the result of a new federal law allowing Bonneville Power Agency to reduce rates to certain small users in selected locations in return for increases on other larger users in Bonneville's territory.

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 judgement 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.

The results of operations adopted by the Commission reflect most of the revenue, expense, and rate base adjustments recommended by the Commission's staff. A notable exception is the staff treatment of income taxes, specifically ITC. The position of Pacific is adopted by the Commission because it reflects actual credits available for 1982, whereas the staff version reflects credits earned during 1982. The difference for this rate case is substantial, the staff method resulting in a much higher revenue requirement than requested by Pacific.

The Commission adopts an overall rate of return for 1982 of 12.8% which provides for 16% on common equity. Another factor affecting Pacific's revenue requirement is the Economic Tax Recovery Act (ERTA). The effect of ERTA is to increase the revenue requirement otherwise adopted herein by $277,000.

This decision increases the overall rates in California by $7,175,000 or 27%, applies an overall kWh increase to residential rates, and eliminates the present $2 monthly charge replacing it with a $2 minimum charge while recouping the lost revenue from an overall energy charge increase for residential users. The Commission believes this best reflects its current policies on encouraging energy conservation through use sensitive pricing.

Pacific requested the Commission to authorize an automatic attrition allowance which would increase rates on January 1, 1983. The Commission finds Pacific's attrition proposal to be unreasonable and invites Pacific to request an attrition allowance based on a methodology similar to that adopted by this Commission in its other recent electric utility rate decisions.

<u>Issues</u>

The following is a summary of the major issues in this proceeding in the order they will be discussed in this decision.

1. Jurisdictional Allocations

As they were in A.58605, Pacific's last major rate case, jurisdictional allocations were again a major issue. Toward Utility Rate Normalization (TURN) urged the Commission, as it did in A.58605, to adopt TURN's growth share method of allocation in lieu of the integrated system method used by Pacific. The staff proposed a new allocation alternative, the "relative use" method.

2. Revenue Estimates

Pacific and the staff were the only parties to present complete estimates of results of operations for the test year 1982. For the most part Pacific and the staff are in agreement except for commercial sales; Pacific contends that if the staff commercial sales revenues are correct, then staff has underestimated the amount of service required for the rate year.

3. Operating Expenses

Pacific accepts the staff estimates for operating expenses for the test year 1982 with the exception of an adjustment for purchases of coal from the Bridger Coal Company (Bridger), a wholly owned subsidiary of Pacific. The adjustment proposed by the staff is similar to the one we adopted in the last rate proceeding.

4. Rate Base

The major differences in rate base estimates between Pacific and the staff involve certain unamortized leasehold improvements, removal of overburden at coal mining facilities, relicensing expenses, various special studies, and computer models. The staff estimate for working cash allowance was higher than Pacific's because staff used certain updated information and a later period of time for its estimate.

5. Rate of Return

Pacific requests an overall rate of return of 12.19% for 1982 based on an equity return of 16.25%. Staff recommends between 11.72% and 11.90% overall and 15.25 to 15.75 for equity.

6. ITC

The major difference between Pacific and the staff is the estimate of ITC for test year 1982. The staff estimate of ITC for ratemaking purposes was considerably below that of Pacific, thereby producing a much higher income tax liability. The liability was so much higher that, if the staff estimate were accepted, the revenue requirement would be several million dollars higher than Pacific requested.

7. Rate Design

Again, as in past proceedings, the rate design issues were hotly contested. In general, Pacific recommends a uniform percentage increase and the staff recommends a uniform cents-per-kWh increase. The California Farm Bureau (Farm Bureau) argued strongly against any increases in agricultural pumping charges because of competitive pressures from Oregon agriculture. TURN recommended elimination of the flat residential customer charge, proposing to replace it with increased energy charges for the residential class.

8. Conservation

Staff recommended Pacific's expenses for conservation activities be reduced and that a system of rewards and penalties be instituted based on Pacific's achievement in conservation areas. Pacific claimed that if the Commission adopts this, Pacific should have an opportunity to offer explanations for any failures it may have had in achieving its conservation goals prior to suffering any penalty.

9. Attrition Allowance for 1983

In addition to the 1982 test year increase, Pacific requests another $2,451,000 (6.5%) rate increase to take effect automatically in January 1983. TURN in particular opposes the policy of granting rate increases more than a year in advance based on inflation patterns which may or may not occur.

Allocation Procedures

In D.92411, A.58605, we included an extensive discussion of jurisdictional allocation procedures used or proposed by the parties. In that decision we indicated that we did not support the existing methodology used by Pacific, that we saw merit in the growth share alternative proposed by TURN, but that we did not want to take unilateral action on the jurisdictional allocation issue without consulting with the other states in Pacific's service territory.

The record in this proceeding strengthens our conclusion that the existing cost allocation methodology is in need of change. The existing integrated system method was adopted in a time of declining utility costs, when excessive growth in demand was promoted rather than avoided. Since that time, rapidly increasing energy costs have made the efficient use of energy resources a paramount policy objective for the nation. The greater use of ~~economic principles~~ marginal cost in allocating costs and designing rates in recent years has allowed this policy objective to be furthered. Indeed, this was a primary reason for Congressional direction, in the Public Utilities Regulatory Policy Act of 1978, to the states to consider marginal cost principles in their cost-of-service ratemaking.

SS

As Pacific's witness Kahn pointed out, the present method is not consistent with economic principles and efficient resource use, except possibly "by accident." After an initial jurisdictional allocation is made, states can seek to subdivide their portion as best they can to develop rates that promote efficient resource use. But as both Kahn and TURN witness Wells agreed, the initial allocation, in determining overall rate levels within individual states, contributes in an important way to the degree to which efficient resource use and conservation is encouraged across the utility's system. If the existing system does not allocate costs in a manner consistent with economic principles, then efficient resource use will not be enhanced and the efficacy of individual states' efforts to avoid excessive system costs will be lessened.

Even if embedded costs were taken as the proper guide to cost-of-service ratemaking, the present method would be inadequate in our view. As staff witness Han pointed out, the present method errs by allocating all of the company's substantial baseload capacity costs according to winter peak demand responsibility. This is done even though, as Pacific witness Sirvaitis clearly indicated, that such facilities are built for energy and not to meet peak load reliability needs. In this way, even within an embedded cost philosophy, the present method incorrectly assigns cost responsibility and thus discriminates unfairly against relatively lower load factor jurisdictions in Pacific's system, such as California, Oregon, Montana and Washington.

The time is ripe for the consideration of a new jurisdictional cost allocation methodology which is fairer and more clearly consistent with economic principles. In D.92411 we stated that we did not wish to take action on the allocation methodology without first consulting with other states. We regret to say that such consultation has not been carried out to date. While we consider cost allocation, like rate of return and other ratemaking issues, to ultimately be a matter of individual state authority it is clearly preferable to achieve a multi-state consensus on cost allocation procedures.

In this decision we do not grant to Pacific any portion of its proposed rate increase that is disputed by the parties on the basis of differing jurisdictional allocation methods. Instead, we will leave open this proceeding on the issue of jurisdictional cost allocation and incorporate the relevant portions of the record from the present phase of the proceeding into the further hearings. Other states and interested parties will be invited to participate. We will arrange for the reproduction of relevant portions of the record to be made available at our expense to any of our sister states that request such information. We also note the availability of Western

Conference of Public Service Commission's financing to facilitate the participation of other states. We thereby hope to develop a record that incorporates the views of the various states in which Pacific operates.

After our final decision on the allocation method as it relates to Pacific's California customers, we will order Pacific to revise its rates upward or downward to reflect the adopted method.

Cost allocation is a technical and complex issue for regulators, but is nevertheless quite important in ultimately simple dollars and cents terms to the multitude of ratepayers who face the monthly bill. We believe the central principle here is that costs should be allocated in proportion to the responsibility for their occurrence. Further, cost responsibility should be defined in forward looking economic cost terms, as is the case in unregulated markets, rather than in backward looking accounting terms. In D.92411 (p. 30) we stated that we saw merit in the growth shares method as an alternative to the present method because it linked increases in demand to incremental costs incurred to meet this demand. We also noted certain disadvantages associated with the procedure, such as the simplified connection between demand increases in one year and new capacity costs in the same year. Further disadvantages were noted in this proceeding, as in Kahn's assertion that growth shares assigns incremental cost responsibility in an unequal way.

Cost allocation is necessarily an inexact science. The regulator's choice is among imperfect alternatives. In addition to the current methodology, the relative use method, and the growth shares procedure, we invite parties involved in the further hearings to consider the long-run incremental cost (LRIC) method that is now used for intrastate allocations by Oregon and California, as well as other methodologies which parties deem worthy of possible adoption. To allow for the analysis of the LRIC alternative, we will order Pacific to prepare a systemwide LRIC study as a basis for jurisdictional cost allocation prior to the further hearings.

Revenue Estimates

Pacific and staff used somewhat different approaches for projecting sales estimates for the test year 1982. However, despite the differences in approach the results were sufficiently close to allow the staff to accept Pacific's projections for all categories except commercial and street and highway lighting.

For commercial sales Pacific based its projections on econometric models, whereas the staff relied on an analysis of historical trends. Staff projects 1982 sales at a level slightly lower than recorded 1980 and at about the same level as 1979; Pacific predicts sales that fall well below those recorded for 1979 and 1980.

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Pacific included in rate base expenses connected with developing a materials management system, a computer accounting system, and a forecast model. Again staff claims these studies will not provide any benefits to ratepayers until they are completed, and because they will not be completed in the test year, staff recommends that the expense should be excluded from rate base until they are completed. The remaining adjustments proposed by staff relate to expenditures the staff claims should be properly treated as either expenses or work in progress.

Pacific claims its Merlin hydroelectric license has indeed expired, but, by attempting to attain licensing of the project, Pacific retains the right to receive relatively low-cost energy from the project during the relicensing period. Pacific claims the computer model will produce benefits over a long period of time and therefore should be included in rate base.

In the operation of the coal mines which supply fuel to Pacific's thermal generation plant at Centralia, Washington, Pacific makes expenditures for removal of the soil and other material which overlie the coal seam. Pacific's approach is to amortize the cost of this overburden removal and to include the unamortized portion in rate base. Staff claims that because overburden expenses are inextricably connected to the mining of the coal, they should not be paid by the ratepayers until the coal is actually used. Also, if the unamortized portion of the expenses are included in rate base, ratepayers are paying an additional amount to maintain a rate of return on rate base. The staff proposal ties the recovery of the overburden expenses more closely to their contribution to the generation of electricity by expensing the overburden removal cost as part of the coal cost.

It appears that for its adjustment of $342,000 the staff applies the principle that items included in rate base should be useful in providing electric service to customers. Staff claims it does not seek to deny Pacific recovery of its expenses, rather, staff proposes an accounting treatment that is fair for Pacific and its ratepayers. Staff's adjustments are reasonable and should be adopted.

Pacific included in rate base $1,002,000 for working cash and the staff $1,694,000. Pacific based its estimate on 1980 expenses; the staff not only used a difference in approach but used information updated to a later period which reflected increased expense levels. Staff believes the results of its study should be used so that Pacific is treated in the same fashion as other electric utilities subject to the Commission's jurisdiction. In A.58605, the staff also performed a working cash analysis that resulted in a figure exceeding Pacific's estimate (D.92411, mimeo. p. 38). In that proceeding, however, the staff recommended no adjustment to Pacific's estimate. In this case the staff is making a recommendation which follows the method the Commission has indicated it wants employed in determining the working cash requirement for electric utilities subject to its regulation. In addition, the staff has made its estimate based on California operations whereas Pacific made its estimate based on system operations with an allocation to California. In fairness, we cannot accept all of the staff estimates which tend to improve Pacific's results of operations and reject those that do not. In this case, the staff approach is fair and reasonable and its working cash allowance will be adopted.

<u>Rate of Return</u>

Table 1 is a summary of the rate of return recommendations of Pacific and the staff.

TABLE 1

Pacific Power & Light Company

Estimated and Adopted Rates of Return
Test Year 1982

Component	Capital Ratio	Cost	Weighted Cost
Pacific			
Long-Term Debt	54%	9.88%	5.34%
Preferred Stock	10	10.02	1.00
Common Equity	36	16.25	5.85
Total	100%		12.19%*
Staff			
Long-Term Debt	54%	9.17%	5.24%
Preferred Stock	10	9.94	.99
Common Equity	36	15.50**	5.58
Total	100%		11.81%
Adopted			
Long-Term Debt	54%	9.87%	5.33%
Preferred Stock	10	9.94	.99
Common Equity	36	16.00	5.76
Total	100%		12.08%

* This represents an update of the original request by Pacific of 12.05%. Pacific did not amend its revenue request, however.

** Staff also showed estimates for common equity at 15.25% and 15.75%. This produced overall returns of 11.72% and 11.90%, respectively.

Pacific, as it did in A.58605, based its estimated return on a mathematical model. The staff based its recommendation on a study of Pacific's operating results compared to other utilities having generally the same business and financial risks. In D.92411, A.58605, at mimeo. 42-47, we included a comprehensive analysis of the methods employed by Pacific and the staff. In that discussion we noted the model used by Pacific is very sensitive to the value chosen for the market capitalization rate. We questioned the objectivity of Pacific in using a formula which depends on a perhaps less-than-objective selection of a single factor. We also criticized the staff approach and see no need to repeat the criticism here.

One item of change was that Pacific used end of test year estimates for debt and preferred stock elements for its cost of capital recommendation. Pacific's witness admitted that his approach overstates the actual cost to Pacific for the test year and that the staff's treatment was a reasonable one, that is, a mid-year average cost of capital for 1982. When Pacific's estimates were recalculated to employ average capital costs for 1982, the resulting figure of 11.93% was within the range recommended by staff, that is 11.72 to 11.90%.

As is usual in rate of return recommendations, the primary difference in the recommendations had to do with return on equity. In this case, Pacific recommends 16.25% and the staff, if averaged, recommends 15.50%.

Both the witnesses for Pacific and the staff agreed that the long-term capital structure objective of Pacific of 54% long-term debt, 10% preferred equity, and 36% common equity should be used. However, the witnesses differed on the cost factors applicable to the components of the capital structure. It appears that both Pacific and the staff witnesses made relatively low estimates of the cost of projected debt issues. For instance, the staff witness estimated that future issues of debt would be at about 16%, whereas the latest included in this record came through at an effective cost of 18.6%.

There was also an issue of whether or not Pacific would issue an additional $175,000,000 worth of debt in 1981. The staff witness, in the preparation of his first exhibit, estimated that $175,000,000 would be issued at 16%. As things developed during the proceedings $100,000,000 of that was actually issued at 18.6%. The staff witness then eliminated in a revised exhibit the remaining $75,000,000 from his estimate.

Pacific claims that it will issue the $75,000,000 during 1981 or 1982 and therefore, it should be put back into the staff exhibit. It appears reasonable to put the entire $75,000,000 in for 1982 at 16%. Staff Exhibit 42 shows the charge for $175,000,000 to be $28,000,000. We will use 75/175 x $28,000,000 or $12,000,000. Exhibit 43 by staff shows average net proceeds and annual charge for 1982 as $1,446,069,000 and $140,450,000, respectively. This produces the 9.71% cost shown on Table 1. If one-half of $75,000,000 and $12,000,000 are added to the $1,446,069 and $140,450,000, respectively, the results are $1,483,569,000 and $146,450,000 which produces an average cost of 9.87%, which we will use for cost of long-term debt.

The last major decision issued by the Commission for a utility furnishing electric service was Pacific Gas and Electric Company (PG&E), D.93887 in A.60153 dated December 30, 1981, which provided PG&E 16% return on equity. We also believe that is reasonable for Pacific and will grant Pacific 16% on equity. The resulting overall return is 12.08% as shown on Table 1.

Results of Operations

Before adopting a results of operations, two issues require discussion and disposition, ITC and the effects of ERTA.

One of the most controversial issues during the proceeding was the difference between Pacific's estimate of $2,653,000 for ITC versus the staff's estimate of $749,000. Even though the staff made several adjustments to Pacific's revenues, expenses, rate base, and rate of return estimates, the lower staff estimate of ITC resulted in the staff showing Pacific requiring a larger rate increase than it had applied for. Because any ITC figures are subject to net-to-gross multiplier, the gross revenue impact of the staff's adjustment amounted to almost a $4,000,000 increase in Pacific's test year revenue requirement under proposed rates. The staff claimed its recommendation was based on previous Commission decisions on the treatment of ITC. However, at the request of the ALJ the staff reviewed these so-called pertinent decisions and could not find any in which the full Commission expressly addressed and supported the position taken by the staff. All it could find was two concurring opinions in D.84568 dated June 17, 1975 involving a case in which the Commission was considering the effects on ratemaking of the provisions of the Tax Reduction Act of 1975 including a provision which permitted a utility a choice of treatments of ITC. Because the Commission could not agree, it discontinued its case on the Tax Reduction Act, but in concurring opinions three Commissioners expressed a preference for the full flow-through approach. Staff's recommendation on ITC in this application reflects a one-year flow-through approach. However, it has been the Commission policy that taxes as actually paid or estimated to be paid during a rate year should be used if the flow-through method is used. In this case Pacific uses the flow-through method and the amount of ITC which is actually available to Pacific in the test year for tax purposes is the amount estimated by Pacific. Pacific claims it could not have the ITC available had it earned its authorized rate of return in the past. Had it been able to do that, it would have used the credits and they would not be available for 1982; and even though Pacific includes the $2,653,000 in its calculation it tends to agree with the staff that only $749,000 should be used because that is the amount estimated to be <u>generated</u> during 1982 rather than actually available to reduce taxes. Pacific further claims it suffers a double penalty if it is forced to bring forward and use in 1982 for ratemaking purposes tax credits which were generated from 1978 to 1981 but not used because of inadequate earnings.

The record is quite clear that on its tax returns for 1982 Pacific will have a large amount of ITC available, most of it carried forward from 1977 through 1981; and regardless of why these credits are there, they are available and can be used by Pacific to reduce its tax liability for 1982 and this should be flowed through to the ratepayers.[1/]

We turn now to the matter of ERTA. In late-filed Exhibit 54 staff provided an estimate of the additional revenue requirement for protection of Pacific's reduced tax liability under ERTA's depreciation guidelines. The relevant amount is $277,000 and is included in the gross revenue requirement used to amend Pacific's rates in this proceeding.

Based on the foregoing discussion of jurisdictional allocation, revenues, expenses, rate base, rate of return, ITC, and ERTA, Table 2 contains the results of operations that we adopt in this interim decision for the test year 1982. It is noted that the revenue requirement of $34,100,000 includes an amendment by Pacific to its original application for an additional $44,383 as a one time reimbursement for the award given to TURN by the Commission in D.93371 in A.58605 under the provisions of the Public Utility Regulatory Policy Act. This amendment is for only one year. Pacific is put on notice that one year from the effective date of this decision rates should be either decreased by $44,383 or jusitification made by advice letter for continuance of rates at the level authorized by this decision.

1/ The carry forwards for 1977 through 1980 are not subject to the normalization restrictions of ERTA.

TABLE 2

PACIFIC POWER & LIGHT COMPANY

Adopted Results of Operations
Test Year 1982

	Present Rates	Authorized Rates
Revenues	$29,925	$34,100
Expenses		
Production	9,303	9,303
Transmission	1,137	1,137
Distribution	1,812	1,812
Customer Acct.	747	761
Customer Services	341	341
Adm. and General	2,619	2,717
Subtotal	15,959	16,071
Book Depreciation	3,621	3,621
Taxes Other	1,499	1,499
State Tax	-	660
Federal Income Tax	-	270
Total Operating Expenses	21,079	22,121
Net Operating Revenue	5,846	11,979
Rate Base	99,181	99,181
Rate of Return	5.89%	12.08%

Note: To reflect our jurisdictional allocation decision, the adopted results are based on the growth share 1968 base year allocation, adjusted to reflect our other decisions, discussed above, on expenses, rate base, rate of return, and ERTA.

Rate Design

Again, as in other areas Pacific and the staff were the only parties to offer complete rate design proposals. Other than the general recommendation of Pacific for a percentage increase in rates and the staff recommendation of a uniform cents-per-kWh increase, other rate design areas of controversy included irrigation rates, small general service rates, residential customer charge, a minimal seasonal charge for agricultural pumping, a five-year contract provision for agricultural customers, and a small but volatile problem with something called the reactive power charge.

D E L E T E D

D E L E T E D

The proposed increase for irrigation rates produced a stormy reaction from farmers in the Yreka area. Pacific's rate design proposal would increase irrigation rates substantially and the staff's design would increase such rates even more. The main reason for the difference between the two is Pacific's recommendation of irrigation rates reflecting the overall increase and staff's recommendation of a uniform cents-per-kWh increase. Because under present rates the irrigation rate is considerably lower than the average system rate, (2.663 vs 3.451) the staff proposal results in the much higher percentage increase.

During the hearings, the result of a congressional bill known as the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act)[2/] became known; its effect on Oregon ratepayers incensed California ratepayers, particularly the agricultural segment which competes with Oregon agriculture. One result of the act is that residential and small agricultural users in Oregon will be paying 20% less for their power than they would ordinarily.

The average cents per kWh in Oregon without the Northwest Power Act reduction and with the rates proposed by Pacific for 1982 would be 3.80 cents per kWh compared to the proposal in California of 4.83 cents. The following table shows the system average cents per kWh at proposed rates for 1982 for the various states served by Pacific without the Northwest Power Act reduction.

	¢/kWh
California	4.83
Montana	4.26
Oregon	3.80
Washington	3.27
Wyoming	3.02
Idaho	2.90

2/ SB 5 - Public Law 96-501, 96th Congress; 16 USC 839 et seq. Dec. 5, 1980.

If we reduce the Oregon proposed rate of 3.80 cents by 20%, the result is 3.04 cents per kWh. As will be noted in the concluding paragraph of this section, irrigation rates will be set at 3.382¢/kWh, the residential lifeline rate. This will result in an irrigation rate increase of 27%. We know this is contrary to the staff recommendation that where no long-run incremental cost information is available, rates should be increased by the average increase in cents per kWh. Staff's recommendation is based on the policy goal of improving efficient use of energy by approaching marginal cost pricing in the absence of long-run incremental cost studies. In this particular case, however, we must recognize the competitive aspects between Oregon and California agriculture and make allowances for them.

Staff recommends a substantial reduction in Pacific's proposed rates to small general service customers because it believes Pacific has included too much for distribution costs to serve such customers. Staff asserts that for Pacific's convenience it installs oversized distribution systems for the small demand customers. Staff maintains this oversizing, and thus overinvesting, is without economic justification. Therefore, it reduced its estimate of distribution costs for small general service customers to the costs for the next larger service which is between 15 and 30 kW.

Pacific maintains there are two reasons supporting its proposed rates. First, the needs of such small customers require a transformer which is not commercially available below a certain minimum size. Thus, of necessity, the transformer capacity installed to serve the smallest customers will be greater than the customers actually use. Second, the needs of small general service customers can be expected to vary more than residential customers. A given small general service customer at a specific location may initially require a relatively small transformer. However, if Pacific installs a small transformer and the customer's load increases unexpectedly or is replaced by another customer requiring a larger transformer, Pacific incurs the additional cost of removing the small transformer and installing the larger.

Staff claims Pacific has provided no study indicating it is cheaper initially to install an oversized transformer than to replace it. Because the transformers are investments subject to a rate of return any overinvestment would require higher revenues and be to Pacific's benefit.

We believe Pacific's position reflects a reasonable managerial decision; the size and amount of distribution facilities and resulting rates should be accepted.

TURN proposed that the residential customer service charge of $2 be eliminated. The recovery of the lost revenues would be through an increase in the energy charge. Pacific claims that the customer charge which was instituted in the last general rate case (D.92411) should be continued because it gives customers a clear price signal that expenses are incurred in providing their service facilities, reading their meters, and rendering bills. TURN believes that fixed charges such as the customer charge discourage conservation by holding down the kWh rates. As a result, the savings that a customer receives by conserving energy is smaller than it would be otherwise.

In line with the conservation principles noted by TURN, we think it is appropriate to eliminate the $2 service charge, replace it with a $2 minimum charge, and recover the lost revenue through an overall cents per kWh increase on residential rates. Also, we will maintain the 50% differential between lifeline and nonlifeline rates in the residential class. In addition, we believe setting the residential class at the average system rate as we did in D.92411 is appropriate.

Pacific proposes a five-year contract for irrigation customers using the PA-20 (irrigation) tariff. A customer would sign a written contract having a term of not less than five years. Pacific believes five years is the time period required to justify adding facilities for agricultural customers. Pacific's economic justification for this proposal, however, was very weak. After much cross-examination, Pacific eventually submitted Exhibit 31 which allegedly supported a contract term of five years. Pacific claimed that 30 inactive irrigation accounts currently exist and an additional 30 with little or no usage could become inactive. However, all of the 30 inactive customers could have become inactive after having been active for a number of years and could have paid for costs of installation many times over. Pacific also produced late-filed Exhibit 51 which showed that during 1979, there were 50 inactive Schedule PA-20 accounts that discontinued service within five years of commencing service and that an additional 73 accounts were inactive at the end of 1979 that had commenced service prior to 1974.

Pacific provided no evidence to show what its added costs are nor why a five-year contract period would ensure recovery of costs. We can see no reason to institute such a program absent a better showing on the part of Pacific.

The matter of a reactive power charge became an item of controversy in spite of the fact that it appears to involve only about $168 in yearly revenues. Although the mathematical calculation of the charges is quite simple, the language describing the charge that would be assessed is very confusing. Both the rate design witnesses for Pacific and the staff stated it is necessary to have a "kvarh" meter and a reading from such a meter before a reactive power charge can be assessed against a PA-20 customer. There is no evidence of what tariff provision would cover such a meter. We will deny Pacific's request and invite Pacific to put in more substantial evidence in its next rate case.

In summary, the adopted rate design sets the residential total equal to the average system cents per kWh, residential nonlifeline 50% above lifeline, large accounts and irrigation at the residential lifeline rate, USBR and streetlighting at the system average increase, with the residual revenue requirement to other commercial and industrial. Table 3 shows rates reflecting the above considerations applied to the required revenue shown on Table 2.

TABLE ~~3~~ 2

Pacific Power & Light Company

Rates Under Adopted Revenues
Authorized Rates
1982

Class	Sales kWh '000	Revenue $000 Present Rates	Revenue $000 Auth. Rates	¢/kWh	Increase Percent	Increase ¢/kWh
Lifeline	201,863	$ 5,660	$ 6,827	3.382	20.6	0.894
Nonlifeline	167,294	7,133	9,349	5.588	31.1	1.317
Residential Total	369,157	12,793	16,176	4.382	26.4	0.917
Com. & Ind.						
Large Accts.	63,328	1,722	2,187	3.453	27.0	0.734
Irrigation	94,258	2,150	3,188	3.382	27.0	0.719
USBR	24,539	274	348	1.418	27.0	0.302
Other Com. & Ind.	215,542	9,092	11,607	5.385	27.7	1.167
Streetlighting	4,291	221	281	6.549	27.1	1.539
Total	771,115	26,612	33,787	4.382	27.0	.931
Temp. Service Chrg.			27			
Ret. Check Charge			2			
Total			33,816			
Other Oper. Rev.			284			
Total			34,100			

Conservation Programs

Staff made several recommendations concerning Pacific's energy conservation programs. Pacific does not contest most of them. The effect of the recommendations is to reduce Pacific's customer service and information expenses for the test year to $341,000 through adjustments of $48,000. The adjustments involve a reduction of $24,000 for agricultural pump testing expenses, $9,000 for business energy audits, and $15,000 for a proposed cash rebate incentive program unless Pacific files a complete explanation and justification for the expense.

In addition to its recommendation that Pacific's expenses for conservation activity be reduced staff suggests a system of rewards and penalties be instituted for Pacific's level of conservation achievements. If the Commission adopts such a system Pacific wants an opportunity to explain any failure to meet preset goals prior to suffering any penalties. The record shows there is a shortage of qualified contractors in Pacific's service area and therefore even if Pacific makes all reasonable efforts to achieve convservation goals the contractor shortage may hamper its progress. Also, staff acknowledged that consumers, despite the benefits of conservation, may arbitrarily reject participation in the programs. During the present period of unusually high interest rates and chaotic economic conditions, particularly in the Crescent City area, consumers may be relatively unwilling to commit to the expense of conservation programs.

We will accept the staff recommendation concerning Pacific's conservation expenses but hold any rewards or penalties system over until Pacific's next general rate case.

The other recommendations made by the Conservation staff were that Pacific should:

1. Provide staff with a copy of its updated estimate of Home Energy Audit savings studies as soon as it is available.

2. Provide staff with its memoranda report on ZIP weatherization progress and plans for meeting the cost and activity goals estimated in the 1982 workpapers.

3. Monitor the relative response rate of Home Energy Audit customers who voluntarily submit their names to be given as leads to contractors versus those who do not.

4. Provide as soon as possible the following as called for by staff in 1981:

   a. Three CVR Phase II studies.

   b. An experiment with Phase I adjustment on feeders not presently planned for conversion and a schedule for such tests.

   c. A proposal for a low-income direct weatherization program as discussed in Exhibit 41.

The above recommendations are reasonable and will be adopted. However, the three CVR Phase II studies were submitted to the Commission on November 2, 1981. Therefore, 4.a. above is unnecessary.

Attrition Allowance - 1983

Pacific requests authorization for an increase to become effective January 1, 1983 to compensate for attrition. Under Pacific's proposal, there would be a 6.5% rate increase on January 1, 1983 producing additional annual revenues of $2,451,000. Pacific claims that even though it is not on the Regulatory Lag Plan it would like to be on a cycle of filing general rate cases every other year. If an attrition allowance is provided in this proceeding, Pacific would not anticipate filing for a general rate increase until 1983 to become effective in 1984. Pacific points out that it is different from other California utilities because it does not have automatic or semiautomatic adjustment clauses designed to pass through to ratepayers between general rate cases the impact of increases or decreases in certain costs.

In addition to the attrition allowance Pacific proposes a somewhat complicated method which it believes will protect both ratepayers and shareholders from significant changes in costs outside the normal general rate case proceedings. For instance, Pacific proposes that for 1982, the first year the proposed rates will be in effect, Pacific will pass through increases or decreases only if they are related to government-mandated changes or major changes clearly beyond Pacific's control. Such increases or decreases will be passed through only if the total revenue requirement associated with them is equal to or greater than $500,000. Further, Pacific would be required to demonstrate that the increase would not improve its actual return on equity and that its achieved return would not exceed the allowed return. All such adjustments would be on a prospective basis. For 1983 Pacific proposes a different method. It would not request a rate increase or decrease in 1983 unless it experiences a 50 basis point decrease or a 25 basis point increase in the then prevailing rate of return as adjusted. Adjustments to the rate of return would be allowed only if fixed charges as actually incurred differed from those estimated. If Pacific overachieves at a level of 25 basis points greater than the allowed return, it would be required to file a rate decrease to bring the rate of return down to the ordered rate of return. If the rate of return is 50 basis points below that allowed, Pacific could file for a rate increase. However, such an increase would only be sufficient to bring the company up to the allowed rate of return less 25 basis points. Therefore, even after the increase, Pacific would only be allowed to earn less than the amount found reasonable. Pacific claims the proposal would not provide a guaranteed rate of return nor inhibit managerial incentive to provide service on a least-cost basis.

TURN opposes in principle the policy of granting utility rate increases more than a year in advance on the basis of inflation that may or may not occur. TURN claims that granting an attrition allowance does not in any way guarantee ratepayers that further increases will not be requested and granted and cites D.92656 in PG&E's A.59902. TURN believes an attrition allowance tends to become a self-fulfilling prophecy. TURN suggests that should the Commission consider granting both an attrition allowance and a mechanism to handle specific major cost offsets, it should define major more strictly than Pacific has proposed and suggested $2,000,000 or 200 basis points as benchmarks.

It appears that what Pacific is requesting is far more complex than the situation deserves. Further, we do not share the apparent aim of the proposal to fully insulate the company from all cost changes in such a way that a risk-free, cost-plus operating environment is created.

Instead, we invite Pacific to file a 1983 attrition allowance patterned after those authorized for PG&E and San Diego Gas & Electric Company in D.93887 and D.93892. This attrition allowance should be based on the results of operations for the 1982 test year adopted in this decision and should take into account any modifications of the 1982 results that arise from the final cost allocation decision discussed above.

Other Staff Recommendations

Staff made several recommendations not directly contested by Pacific. Staff requests the Commission include the following recommendations in its order:

1. In its next general rate application Pacific should perform a longrun incremental cost study for agricultural customers (PA-20) and for agricultural pumping service provided to the US Bureau of Reclamation. Staff believes this information is crucial to the equitable distribution of rate increases among classes of customers.

2. Pacific should carry out a program of converting outdoor mercury vapor lamps of 21,000 and 55,000 lumens to high-pressure sodium lamps over the next two years. Pacific should continue to monitor the economics of converting 7,000 lumen mercury vapor lamps to high-pressure sodium lamps and should begin a conversion program for these lamps when they become economically justified.

3. Schedule LS-52 covering company-owned special street and highway lighting services and Schedule LS-53 for privately owned special street and highway lighting service should be revised to eliminate the appearance that company-owned service receives a lower energy rate than comparable privately owned service.

4. To improve energy efficiency in street and outdoor lighting Pacific should provide customers information on the energy use expressed in kWh for each light covered under the street and outdoor lighting schedules.

5. The elimination of the declining block rates for Pacific's tariffs should be expanded to include Schedule A-32.

Findings of Fact

1. By this application Pacific requests increases in its electric service revenues for its California customers in the amount of $10,347,000 or 36% over revenues under present rates based on the test year 1982.

2. Public hearings in this application were held during 1981 at which all interested parties had an opportunity to be heard.

3. Pacific also requests an increase to become effective January 1, 1983 to compensate for attrition.

4. Pacific requires additional gross revenue of $277,000 over what the Commission would otherwise grant in this decision so the order which follows will preserve Pacific's eligibility for the benefits of ERTA.

5. Further hearings on the jurisdictional cost allocation issue are necessary.

6. Portions of Pacific's rate request that are disputed on the basis of differing jurisdictional allocation methods should be the subject of final Commission decision after the further hearings.

7. The sales, revenue, expense, and rate base estimates of the staff for the test year 1982 are reasonable.

8. The revenue requirement for test year 1982 includes $44,383 to cover Pacific's payment to TURN for TURN's PURPA participation in A.58605.

9. The investment tax credit as calculated by Pacific for income tax purposes is reasonable.

10. An overall rate of return of 12.08% which includes a return on equity of 16% is reasonable.

11. The results of operations shown on Table 2 are reasonable for the test year 1982 and will produce a revenue requirement for Pacific of $34,100,000.

12. The rate design shown on Table 5 is reasonable and will produce the additional revenue requirement of $7,175,000 for the test year 1982.

13. Pacific's proposal for irrigation customers to sign up for a five-year contract before service would be provided is unreasonable.

14. Pacific's proposal concerning a reactive power charge is unreasonable.

15. The staff's recommendations on conservation measures with the exception of the penalty provision proposed in Exhibit 41 are reasonable and will be adopted.

16. Pacific's proposal for an attrition allowance procedure for 1982 and 1983 is unreasonable.

17. Other staff recommendations contained in staff exhibits and noted in this decision are reasonable and will be adopted.

18. 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.

19. Because the rate year on which the increases authorized is underway there is an immediate need for rate relief.

<u>Conclusion of Law</u>

Based on the foregoing findings of fact and under PU Code § 454 the Commission may grant Pacific authority to increase rates as provided for in the following order to enable Pacific to earn additional annual revenues of $7,175,000.

INTERIM ORDER

IT IS ORDERED that:

1. After the effective date of this order Pacific Power & Light Company (Pacific) is authorized to file revised rate schedules reflecting the rates and rate increases set forth in Appendix A to this decision and concurrently withdraw and cancel its presently effective schedules. Such filing shall comply with General Order 96-A.

2. The effective date of the revised schedules authorized by Ordering Paragraph 1 shall be 4 days after the date of filing. The revised schedules shall apply only to service rendered on and after the effective date of the revised schedules.

3. Within 60 days after the effective date of this order Pacific shall provide staff with:

   a. A copy of Pacific's updated estimate of Home Energy Audit savings studies.

   b. A memoranda report on ZIP weatherzation progress and plans for meeting the cost and activity goals in Pacific's 1982 workpapers.

   c. A proposed experiment with the Phase I adjustment on feeders not presently planned for conversion and a schedule for tests.

   d. A proposal for a low-income direct weatherization program as discussed in Exhibit 41.

4. For its next general rate application Pacific shall perform a longrun incremental cost study for agricultural customers (PA-20) and agricultural pumping service provided to the US Bureau of Reclamation.

5. Pacific shall carry out a program of converting outdoor mercury vapor lamps of 21,000 and 55,000 lumens to high-pressure sodium lamps over the next two years.

6. Pacific shall continue to monitor the economics of converting 7,000 lumen mercury vapor lamps to high-pressure sodium lamps and should begin a conversion program for these lamps when they become economically justified.

7. Pacific shall monitor the relative response rate of home energy audit customers who voluntarily submit their names to be given as leads to contractors versus those who do not.

8. Pacific shall provide customers information on the energy use expressed in kilowatt-hours for each light covered under the street and outdoor lighting schedules.

9. Within 60 days from the effective date of this decision Pacific shall submit a systemwide long-run incremental cost study. The study should be suitable for jurisdictional cost allocation, based on the number and type of customers in each jurisdiction and their timing and level of demand. Jurisdictional LRIC percentages should be derived for use in allocating the revenue requirement. Pacific shall serve this study upon the chairpersons of the relevant state regulatory commissions within its service territory.

10. The Executive Director shall make available to other state commissions reproductions of portions of the record in this proceeding relevant to jursidictional allocation at their request.

11. Hearings on jurisdictional allocations should be held within 90 days of the effective date of this decision.

12. Within 90 days from the effective date of this decision Pacific shall file by the advice letter procedure proposals for revising its tariffs to:

a. Eliminate the appearance that company-owned service receives a lower energy rate than comparable privately owned service covered by Tariff Schedules LS-52 and LS-53.

b. The declining block rates in Tariff Schedule A-32.

13. One year from the date tariff changes authorized by this decision are effective Pacific shall decrease its rates on an equal cents-per-kWh basis so that overall annual revenues are reduced by $44,383.

14. In all other respects A.60560 is denied.

This order is effective today.

Dated MAY 4 1982, at San Francisco, California.

I dissent. I would adopt Administrative Law Judge Porter's decision.

John E. Bryson
Commissioner

RICHARD D. GRAVELLE
LEONARD M. GRIMES, JR.
VICTOR CALVO
PRISCILLA C. GREW
Commissioners

Schedule No. A-32

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.

NET MONTHLY RATE

The Net Monthly Rate 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.
$.62 per kw for each kw of of Billing Demand in excess of 100 kw.

Energy Charge:

6.421¢ per kwh for the first 6,000 kwh plus 75 kwh per kw for each kw of Billing Demand in excess of 20 kw.
4.591¢ per kwh for all additional kwh.

(Continued)

Schedule No. A-36

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.

NET MONTHLY RATE

The Net Monthly Rate 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:

3.243¢ 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)

Schedule No. AT-48

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

Energy Charge:
2.990¢ 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 Company's standard secondary distribution voltage.

Metering: For so long as metering voltage is at Company'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 Company'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 Company-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.

Schedule No. AWH-31

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.

NET MONTHLY RATE

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

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

Energy Charge:

3.083¢ 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)

Schedule No. D

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 lifeline allowance will apply unless lifeline allowances available for electric space heating and/or electric water heating are qualified and elected.

TERRITORY

Within the entire territory served in California by the Utility.

NET MONTHLY RATE

The Net Monthly Rate shall be the greater of the Energy Charges or the Minimum Charge.

RATES

Energy Charge:

	Per Month	
	Lifeline Rates	Non-Lifeline Rates
All kwh per kwh	3.807¢	5.725¢

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.

(Sheet 1 of 3)
(Continued)

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SCHEDULE NO. DM-9

APPENDIX A
Page 6

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 lifeline allowance will apply unless lifeline allowances available for electric space heating and/or electric water heating are qualified and elected.

TERRITORY

Within the entire territory served in California by the Utility.

NET MONTHLY RATE

The Net Monthly Rate 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)

Schedule No. DS-8

MULTI-FAMILY RESIDENDIAL SERVICE - SUBMETERED

APPLICABILITY

Applicable to single-phase alternating 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 lifeline allowance will apply unless lifeline allowances available for electric space heating and/or electric water heating are qualified and elected.

TERRITORY

Within the entire territory served in California by the Utility.

NET MONTHLY RATE

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

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

MINIMUM CHARGE

The Minimum Charge shall be calculated in accordance with the applicable 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 submetered single-family dwelling units or apartments

(Continued)

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Schedule No. LS-51

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.

NET MONTHLY RATE

Nominal Lumen Rating	Rate per Lamp
5,800	$ 6.71
22,000	11.95
50,000	22.61

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.

Schedule No. LS-52

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.

NET MONTHLY RATE

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 6.650¢ 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)

Schedule No. LS-53

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.

NET MONTHLY RATE

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 6.650¢ per kwhr.

b) Where the customer operates and maintains the system, a flat rate equal to one-twelfth the estimated annual energy cost at 6.650¢ 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.

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

Within the entire territory in California served by the Utility.

I. NET MONTHLY RATE 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	$3.34	$4.12	$6.86	$9.78	$12.78
Mercury Vapor Lamps					
Nominal Lumen Rating				7000	21000
Rate per Lamp - horizontal				$7.92	$14.67
Rate per Lamp - vertical				$7.38	$14.32

Street lights on metal poles:

Mercury Vapor Lamps		
Nominal Lumen Rating	7000	21000
Rate per Lamp		
Horizontal	$10.13	—
Horizontal		$17.41

B. Underground System

Street lights on metal poles:

Mercury Vapor Lamps		
Nominal Lumen Rating	7000	21000
Rate per Lamp		
Horizontal	—	$20.93
Vertical	—	$18.98

(Continued)
(Sheet 1 of 2)

Schedule No. LS-57

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

II. NET MONTHLY RATE 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	55000
Rate per Lamp	$8.65	$15.26	$32.72

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.

(Sheet 2 of 2)

Schedule No. LS-58

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.

NET MONTHLY RATE 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	
1,000	$ 2.46	$ 3.68
2,500	4.85	6.12
4,000	7.91	9.23
6,000	10.84	12.21
	MERCURY VAPOR	
7,000	$ 5.05	$ 5.79
21,000	11.44	12.23
55,000	27.40	28.47
	FLUORESCENT	
21,400	$10.84	$12.79

(Continued)
(Sheet 1 of 2)

A.60560 /ALJ/bw

Schedule No. OL-15

OUTDOOR AREA LIGHTING 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.

NET MONTHLY RATE

Type of Luminaire	Nominal Lamp Rating	Per Luminaire Per Month
Mercury Vapor	* 7,000 lumens	$ 9.16
" "	*21,000 "	17.80
" "	*55,000 "	37.63
High Pressure Sodium	5,800 "	$11.24
" " "	22,000 "	17.08
" " "	50,000 "	27.81

*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.

Schedule No. OL-42

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.

NET MONTHLY RATE

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

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

Energy Charge:

6.150¢ 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.

Schedule No. PA-20

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 Company 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 27 through November 27:

Energy Charge:
3.653¢ per kwh for the first 14,000 kwh
2.723¢ per kwh for all additional kwh

Meter Readings from November 28 through March 26:

Demand Charge:
$1.00 per kw of monthly Billing Demand

Energy Charge:
5.403¢ per kwh for the first 100 kwh monthly per kw of monthly Billing Demand
3.593¢ 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)
(Sheet 1 of 2)

Schedule No. PA-20

AGRICULTURAL PUMPING SERVICE
(Continued)

ANNUAL CHARGE (collected in November Billing Period) (Continued)

If Load Size is:	Annual Charge is:
Three-phase service:	
50 kw* or less	$10 per kw* but not less than a Basic Charge of $72
51 to 300 kw*	$100 plus $8 per kw*
Over 300 kw*	$700 plus $6 per kw*

* 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.

BILLING DEMAND

The measured kw shown by or computed from the readings of Utility's demand meter, or by appropriate test, for the 15-minute period of customer's greatest use during the billing month, but not less than two kw; provided, however, that for motors not over 10 hp, the demand may, subject to confirmation by test, be determined from the nameplate hp rating and the following table:

2 HP or less	2 kw
From 2.1 through 3 HP	3 kw
From 3.1 through 5 HP	5 kw
From 5.1 through 7.5 HP	7 kw
From 7.6 through 10 HP	9 kw

SPECIAL CONDITIONS

1. An application of the monthly rate which includes energy in excess of 750 kwh per kw will be computed with such excess at the average price per kwh of the first 750 kwh per kw.

2. When a monthly billing computes at less than $3.00, the consumption will instead be carried forward to the succeeding month.

3. At the option of the customer, irrigation season energy charges may be prorated from March 1 through October 31, provided the customer furnishes Company with the meter readings necessary for determining such prorated billings.

(Sheet 2 of 2)

(END OF APPENDIX A)