ALJ/km/ec *

Decision No. 92411 November 18, 1980 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 No. 58605 (Filed January 17, 1979)

(For appearances see Decision No. 91326.)

Additional Appearances

Antone S. Bulich, Jr. and Allen R. Crown, Attorneys at Law, for California Farm Bureau Federation and Norman G. Edwards, for himself, interested parties.
William J. Jennings, Attorney at Law, for the Commission staff.

SECOND INTERIM OPINION

By this application Pacific Power & Light Company (Pacific) requests Commission approval to increase electric rates for its California service. By Interim Decision No. 91326 dated February 13, 1980 in this matter, Pacific was granted a partial general rate increase which was estimated to produce $4,276,000 in additional annual revenues, a 25.2 percent increase over prior rates based on the test year 1979.

We noted in Decision No. 91326 that there were 16 issues in this proceeding, all but two of which could be decided on the record made prior to that decision. Those two involved questions on allocations to California from the Pacific system and the spread

TABLE OF CONTENTS

of Del Norte County lifeline allowances over the calendar year. Accordingly, we ordered additional hearings to further develop the record on those two issues. Also, we deferred discussion and resolution of the other issues to this final decision. After a prehearing conference in Crescent City on March 7, 1980, the further hearings were held in Crescent City on May 12 and 13, and in Yreka on May 14, 15, and 16 before Administrative Law Judge (ALJ) Albert C. Porter.

The following are the 16 issues in the order we will discuss them in this decision.

1. Allocations.
2. Expenses.
3. Rate base.
4. Property tax savings.
5. Affiliate relationships.
6. Rate of return.
7. Wage/price guidelines.
8. Rate design.
9. Del Norte County lifeline.
10. Lifeline eligibility and status.
11. Refunds due to lifeline mischarging.
12. Residential well pumping.
13. Master metering/submetering.
14. Impact of increases on schools and hospitals.
15. Conservation programs.
16. Conservation Voltage Regulation (CVR).

Decision Summary

In February 1980, the Commission authorized Pacific to increase its rates for California customers by $4,276,000, an average of 25.2 percent above rates then in effect. The increase was on an interim basis pending further hearings and this final decision. The purpose of the further hearings, which were held in May in Crescent City and Yreka, was to develop additional evidence on allocations of system cost factors to California and the spread of the Del Norte County lifeline kilowatt hour (kWh) allowances over the calendar year.

This decision authorizes rate increases to provide increased annual revenues from Pacific's California service area in the amount of $1.366 million or 5.8 percent above the interim increase. Nevertheless, that is more than $600,000 less than Pacific requested.

This decision orders two significant changes for consumers in Pacific's territory. First, for Del Norte County only, the winter period for usage of the lifeline allowance is extended from six months to eight months. This means that the yearly allowance of 6,720 kWh at a reduction in cost of one-third under average residential rates will be available from October through May at 840 kWh per month instead of 1,120 per month from November through April. This should help consumers who moderate their energy use to achieve a minimum total yearly electricity bill. Second, in order to provide for a more uniform monthly billing over a one-year period, Pacific will offer its customers the option of a budget billing system. Under this system customers may be billed one-twelfth of their estimated annual bill for 11 months and in the 12th month enough additional to equal the actual annual bill incurred.

A major issue in this proceeding was the appropriate method to be used in allocating costs of operations between California and the rest of Pacific's multi-state service area. A witness for Toward Utility Rate Normalization (TURN) proposed a novel method of allocating costs incurred to meet increased demand based on the relative growth of California service compared to system-wide growth. This method would take into account the slower growth in usage in California by allocating to California less of the expensive new plant needed to satisfy demand growth than would be done under the traditional cost allocation method.

By this decision the Commission concludes that a substantial change in cost allocation is appropriate and that the method proposed by TURN has substantial merit. However, the decision recognizes that unilateral adoption of the new method would invite retaliatory action by other states and perhaps result in federal preemption of the field. The current cost allocation method is maintained, but the Commission declares its intent to bring the issue promptly to the attention of regulatory authorities in other states served by Pacific to achieve a cooperative resolution more consistent with the pressing need to encourage energy conservation.

Allocations - Issues and Positions

Pacific's operation covers public utility power needs in five states[1] and is operated as a single, integrated system. Some means of allocating revenues, operating expenses, and rate base to each state is required because each state regulates the rates for service within its borders.

For that purpose Pacific uses an allocation procedure which, at this time, has been accepted by all five states involved. The staff uses the same procedure, the genesis of which is the "Electric Utility Cost Allocation Manual", an allocation guide published in 1973. It is the product of a study sponsored by the National Association of Regulatory Utility Commissioners (NARUC) and carried out by staff representatives of the California, Michigan, and North Carolina State Commissions and the Federal Power Commission. The method treats the allocation of investment and expenses in the same manner the system is operated, as one, indivisible, interdependent system; each time an allocation is made, all past allocations are ignored, the system being viewed as though a snapshot were taken at the time of allocation. Where it is appropriate and possible, allocations are made on a direct basis, as for example, transmission and distribution plant and expenses. However, the most significant investment and expenses are allocated on system/subsystem relationships of peak demand and power sales.

1/ California, Montana, Oregon, Washington, and Wyoming. Pacific also serves Idaho but it is not included in the integrated system for allocation purposes because service is provided through separate power lines under special contract rates from Washington Water Power, a private utility in the State of Washington.

The following is a general outline of the allocation bases used by Pacific and the staff, which we will describe for purposes of this decision as the "integrated system method."

<u>Rate Base</u>	
Production Plant	- Peak Demand
Transmission Plant	- Local: Direct
	- Joint: Peak Demand
Distribution Plant	- Direct
General Plant	- Various
<u>Expenses</u>	
Power Production	
Fuel	- kWh Sales
Other	- Peak Demand
Transmission	- Local: Direct
	- Joint: Peak Demand
Distribution	- Direct
Customer Accounts & Service	- Billings and/or Direct
Administrative & General	- Various as Overheads

Although the staff uses the same system as Pacific, staff's results of operations, and hence revenue requirement, differs from Pacific's due to several expense and rate base adjustments and staff's rate of return recommendation all discussed elsewhere in this opinion.

Also, the staff recommended Pacific develop and use in its next rate case, a revised method of determining peak demand relationships for allocation purposes. Pacific currently uses December and January coincidental peak demands because, Pacific contends, its system is a winter-peaking system. Pacific, in this case, used 12 data points, the December-January data for the winters of 1972-73 through 1977-78, and trended these through the test year 1979 to obtain the peak demand allocation percent for California.

The staff notes that even though it is staff and Commission policy to use a coincidental peak demand allocation method, and in this proceeding the staff sees no reason to deviate from that policy, it would be preferable to use a 12-month, or at least a 4-month average of peak demands. Pacific believes these figures would be too difficult to develop and unnecessary;[2/] however, the staff recommends Pacific make an effort in its next rate application to use a 12-month approach and at a minimum a 4-month average.

TURN proposes a different allocation procedure from that used by the staff and Pacific, which is discussed later in this decision. But, if the Commission adopts the integrated system method, TURN recommends several adjustments to the procedure. John W. McCabe, testifying for TURN, argued that Pacific should develop an allocation method using coincident demands for each of the 12 months of a given test period. This method would more accurately reflect the costs imposed on the system. He asserted that Pacific should not adjust for normal temperatures when making allocations because the utility must be prepared to serve real loads not just normal loads under average weather conditions. He testified that he did not know whether or not his proposed changes, if adopted, would be advantageous to California ratepayers. TURN brought out that data used by Pacific in developing the peak demand allocation to California extended only to January 1978 and should have included at least December 1978 and, if possible, January 1979. Another point by TURN is that data used for the adjustment of temperatures were based on

---

2/ Table A of Exhibit 41, witness Ferraro, shows that in 1979 the February and November peaks exceeded December and there was about a 20 percent difference between some summer and winter peaks.

the period 1931 through 1960, a period ended almost 20 years from the test year 1979. TURN suggested that it would be more correct to project the trend in peak demand, California as a percent of the system, into 1980 rather than 1979 as Pacific did. This would decrease the 4.00 percent peak demand allocation factor used by Pacific to 3.94 percent; the result would be less investment and expense allocated to California.

Pacific criticizes TURN's arguments as follows. It would be difficult and expensive for Pacific to develop 12-month data on peak demand and the result would probably not change the allocations appreciably. Temperature adjustments are proper because ratemaking for a utility should be based on expected costs under normal conditions and a utility must plan capacity sufficient to meet loads caused by abnormally cold temperatures. Pacific claims it is reasonable to expect that over time the temperature in one jurisdiction will not vary from normal more than the temperature in any other jurisdiction. Therefore, use of unadjusted data for computing temperature-sensitive peak loads, which may periodically benefit or penalize a given jurisdiction, is not consistent with sound ratemaking principles. As to including peak demand data for December 1978 and January 1979, such data were not available to Pacific when it compiled the results of operations for test year 1979 which were included in this application filed January 17, 1979. Pacific does not agree with TURN's argument that a projection should have been made through 1980 for some of the data; Pacific points out that the test year, as accepted for ratemaking purposes, is calendar year 1979 and therefore projections through 1980 would be inappropriate.

For purposes of an integrated system allocation we accept the allocation made by Pacific as adjusted by the staff. Of TURN's proposals for change discussed above, the only two not soundly countered by Pacific are the 12-month peak demand data base and the use of temperature-adjusting data almost 35 years old. The peak demand matter has been addressed by the staff and we agree that Pacific should either show good reason for not developing the data or include them in its next major rate case. As the staff points out, Pacific may have problems preparing a 12-month average coincidental peak demand, not the least of which is its five separate jurisdictions. But the argument that it is too difficult to develop the data is not convincing. On the matter of temperature data, Pacific's witness Reed testified that the data are being updated but only to 1970. It would seem that a later period could be and should be developed.

A final point on allocations brought out by TURN involves the period used to develop the basic data from which percentages are derived to allocate certain expenses. Illustrative of the procedure and the TURN criticism is the manner in which fuel costs are allocated. Taking first the plant in which the fuel is used, the allocation is done by relative demand as discussed earlier. That demand relationship is developed from historical data which are trended into the test year 1979 to obtain an estimate for the test year. However, the estimated cost of fuel used in the plant for the test year is allocated on the basis of kWh sales in the five states for the year ended September 30, 1978, a period 15 months removed from the test year. (The midpoints for the two periods would be April 1, 1978 and July 1, 1979, respectively.) Given the fact that California as a portion of the system has been steadily declining for some years, (see Tables 1 and 2) an allocation based on data 15 months previous to the test year used for ratemaking will result in too much expense allocated to California. If Pacific uses its present allocation system again in California, data used to develop the allocation bases for the various investment and expense items should be from appropriately consistent periods.

TABLE 1

Source: Exhibit 1, Witness Geiger
Tables 1-4 & 1-5

	Average Number of Electric Cust.-Indexed		Annual Average kWh Use Per Res. Cust.				
			kWh		Calif. Over System	Indexed	
	System (1)	Calif. (2)	System (3)	Calif. (4)	(5)=(4)÷(3)	System (6)	Calif. (7)
1968	100	100	10,788	12,061	112	100	100
1969	102	101	11,493	12,685	110	107	105
1970	105	103	11,539	12,542	109	107	104
1971	108	105	12,237	13,371	109	113	111
1972	112	107	12,331	13,183	107	114	109
1973	118	110	12,391	13,252	107	115	110
1974	122	113	12,251	12,907	105	114	107
1975	124	116	12,856	13,984	109	119	116
1976	126	119	12,876	13,748	107	119	114
1977	131	123	12,738	13,939	109	118	116
1978	137	127	12,614	13,432	106	117	111
1979*	139	131	13,462	13,812	103	125	115

*Estimated

TABLE 2

Source: Exhibit 1, Witness Geiger
Tables 1-4 & 1-5

	kWh Sales-Millions		Calif. As Percent Of	kWh Sales-Thousands Indexed	
	System	Calif.	System	System	Calif.
1968	11,867	528	4.45	1.00	1.00
1969	12,199	499	4.09	1.03	.95
1970	13,321	534	4.01	1.12	1.01
1971	14,425	577	4.00	1.22	1.09
1972	16,568	639	3.86	1.40	1.21
1973	17,709	685	3.87	1.49	1.30
1974	16,477	612	3.71	1.39	1.16
1975	18,249	706	3.87	1.54	1.34
1976	20,014	761	3.80	1.69	1.44
1977	19,691	748	3.80	1.66	1.42
1978	22,502	836	3.72	1.90	1.58
1979*	22,980	806	3.51	1.94	1.53

*Estimated

Two other procedures for allocating investment and expense from the system to California were suggested. Both are occasioned by the steady decline of California as a portion of Pacific's system. Again, see Tables 1 and 2. The first of these, which we will call the "state facilities method", was suggested by Norman Edwards, a cattle rancher and customer of Pacific from Little Shasta in Siskiyou County, California. Mr. Edwards' concern is that California at one time had an abundance of cheap hydroelectric power to serve its power needs. And now, it seems, that source is being taken from California and allocated to other states in the Pacific system that are growing at a rate significantly above the California area served by Pacific. That growth in other states, claims Edwards, has required Pacific to build thermal plants which are much more expensive than the hydroelectric facilities of Pacific, particularly those in California. Since the growth in states other than California exceeds that in California, California is allocated those higher costs automatically under the integrated system method. Mr. Edwards testified that Pacific's Exhibit 3 shows that the company-owned hydroelectric capacity of Pacific's total system is 938.5 megawatts (MW); under the integrated system allocation 4 percent, or 37.5 MW, would be allocated to California. But, he points out that California has a total of four hydroelectric plants with a combined capacity of 67.2 MW. Thus, California is not allocated from system hydro capacity an amount even equal to that which it has within its own borders. Pacific counters this with two arguments. First, Pacific points out that Mr. Edwards did not include in the hydro power available that power which is purchased from operators of hydro facilities not owned by Pacific.

When this is added in, and it totals 786.1 additional MW of hydro power, the total allocated to California would be 4 percent of 1724.6 MW (938.5 + 786.1) or 69.0 MW, in excess of the total of 67.2 MW available from California sources. Second, Pacific shows that the total required capacity to serve California, based on the peak demand projected for December 1979, is 153.1 MW, far in excess of the California hydro capacity. Other than the discussion noted above, there is no evidence in the record of the results of operations the state facilities allocation procedure would produce. Responsive to a data request of TURN, Pacific prepared and furnished to TURN Pacific's version of the state facilities method. This apparently went beyond the method suggested by Mr. Edwards, that is, that California be given its hydro plus enough of the remaining system average costs to make up California's required capacity. Pacific's version would first give each state in the system the benefit of the lowest cost generating facilities located within its physical boundaries, and then any deficiency would be obtained from generating facilities considered to be surplus to the area in which they are located. Upon reviewing the study and some of the assumptions it contained, TURN determined that it was not useful for its purposes and did not introduce it.

TURN, through its witness Frederick J. Wells, introduced an allocation procedure which TURN claims makes a fair assignment of the system to California by properly accounting for the differential growth problem. Dr. Wells prefers to call it the "growth share method." Under this procedure growth inequities between states are accounted for by assigning the incremental costs of such growth proportionally to the states responsible for the growth. In its simplest form, if two states have certain capacity requirements at a zero (starting) point in time, the expense of providing the requirement would be allocated based on the percentage relationship of the two requirements. Then, as the system grows, the increase in expense to provide that growth would be allocated on the basis of the growth relationship (growth share) between the two states.

Putting the theory into a numerical example, it would work as follows. At zero point in time, states A and B are served by a single system having a total cost of $100. State A requires 25 percent of the system capacity of 100 units and state B 75 percent. At zero point in time, an allocation of the system cost is made based on the integrated system method of 25 percent x $100 = $25 to state A and 75 percent x $100 = $75 to state B. Say over the next few years the size of the system doubles and the average cost per unit to build the increased plant doubles, today, then, the cost of the system is $300, $100 of old plant and $200 of new plant. Say, also, that state A now requires 20 percent of the capacity of 200 units and state B 80 percent, (state B grew more rapidly than state A) under the integrated system allocation method (Pacific and staff) state A is allocated 20 percent x $300 = $60 and state B 80 percent x $300 = $240. Under the growth share procedure the allocation is made in two parts, old plant and new plant, as follows:

State A's present requirement = 20% x 200 units	= 40	units
State A's zero point requirement = 25% x 100	= 25	
State A's portion of new plant = the difference	= 15	units
State B's present requirement = 80% x 200 units	= 160	units
State B's zero point requirement = 75% x 100	= 75	
State B's portion of new plant = the difference	= 85	units

Allocate the incremental cost for the new plant based on each state's growth share:

State A growth	= 15 units	= 15%
State B growth	= 85 units	= 85
Total growth	= 100 units	= 100%

Incremental cost of new plant to State A = 15% x $200 = $ 30
Incremental cost of new plant to State B = 85% x $200 = $170

Final allocation to State A:	Old plant =	$25
	New plant =	30
	Total =	$55
Final allocation to State B:	Old plant =	$ 75
	New plant =	170
	Total =	$245

Thus, there is a shift of $5 from state A to state B using the growth share method as compared to the integrated system method. In actual application of the method, present costs are used for old plant but for purposes of illustrating the two methods the above will do.

It is important to note that the growth share method assumes a dedication of facilities to the states involved both at the zero point and at any point in time later when an allocation is made. As Dr. Wells states in his prepared testimony (Exhibit 43), "It is based on the concept that the California operations of (Pacific) could be treated as if they were a separate subsidiary or company. This is not unrealistic as some utility companies do form such subsidiaries for different localities and types of services. All that is needed to support the growth share cost allocation is to assume that the California subsidiary of (Pacific) ['California - Pacific'] attempts to minimize its costs of service." Again, (Exhibit 43) when asked the question, "When you allocate the 1968 California share of hydroelectric capacity and purchased power to California customers in 1979, are you not vesting property rights in certain resources?"[3] Dr. Wells replied, "Yes. This matter of vesting rights to cheap resources [hydro in this case] has long been discussed by economists. Such property rights make sense in this situation because it is illogical to expect that the California Commission should not protect California customers from subsidizing growth in other jurisdictions." Dr. Wells testified that the 1968 data base was used as a starting point because it contained the only conveniently available information needed to apply his procedure. Dr. Wells stated that it would be preferable to apply the growth share procedure on a year-by-year basis and use as a starting point the year 1968 or a period earlier if possible. This brings us to a fourth possible allocation procedure which we will call the "incremental growth share method." This method would have a zero point similar to the growth share method whereby the first allocation is made by the integrated system method; from then, on a year-by-year basis, new (incremental) plant is allocated to the jurisdictions responsible for the growth. Table 3 is an attempt to put the four methods we now have to consider into some perspective so they may be understood and compared. Although the relative numbers in terms of units required reflect the general relationship of California to the Pacific system, it is not to be implied or concluded that the results of the allocations in any way illustrate the relative differences that would result from applying the four methods to actual California/Pacific-system allocation units, investments, and expenses.

3/ In applying his procedure to Pacific to obtain California results of operations for ratemaking in this application, Dr. Wells used, as the zero point, the test year results of operations for 1968 as used by Pacific in its rate case before the Commission in 1969, Application No. 51553.

Table 3

A Comparison of Four Allocation Methods

Year (N)	Cost Per Unit Installed Year N	Units Required: State A	Units Required: State B	Total Units	Increase In Units	Increase In Cost	Total Cost
	(1)	(2)	(3)	(4) (2)+(3)	(5) $(4_N)-(4_{N-1})$	(6) (1) x(5)	(7) $(7_{N-1}+6_N)$
0	$10	100 (4.8%)	2,000 (95.2%)	2,100 (100.0%)	2,100	$21,000 (1)	$21,000 (1)
1	11	105	2,200	2,305	205	2,255	23,255
2	12	110	2,400	2,510	205	2,460	25,715
3	13	115	2,600	2,715	205	2,665	28,380
4	14	120	2,800	2,920	205	2,870	31,250
5	15	125 (4.0%)	3,000 (96.0%)	3,125 (100.0%)	205	3,075	34,325

(1) Initial cost of system

Allocation to State A by:

A-Integrated System Method (Pacific/Staff)

$34,325 x 4.0% = $1,373

B-One-Step Growth Share Method (TURN)

Cost to State A at Year 0 = $21,000 x 4.8% = $ 1,008
Units installed after Year 0 = 3,125 - 2,100 = 1,025
Cost of those units = $34,325 -$21,000 = $13,325
% of units installed after Year 0 attributable to State A = $\frac{125-100}{1,025}$ = 2.4%

Cost to State A after Year 0 = $13,325 x 2.4% = $ 320
Total cost to State A = $ 1,008 + $320 = $1,328

C-<u>Incremental Growth Share Method</u>

100 units	x	$10	=	$1,000
5 units	x	$11	=	55
5 units	x	$12	=	60
5 units	x	$13	=	65
5 units	x	$14	=	70
5 units	x	$15	=	75
				$1,325

D-<u>State Facilities Method</u> (Edwards)

Assume State A had 50 units of the total system units at Year 0 at a cost of $5 per unit. Cost of State A facilities in State A = 50 x $5 = $250

Cost of facilities on remainder of system = $21,000 - $250 = $20,750

% of facilities not in State A but needed by State A = $\frac{100-50}{2,100-50}$ = 2.4%

Cost to State A of facilities needed by, but not in State A = $20,750 x 2.4% = $498

Cost to State A after Year 0 = $320 (same as growth share)

Total cost to State A = $250 + $498 + $320 = <u>$1,068</u>

<u>Check for Allocation of 100% of System:</u>

A-To State B: $34,325 x 96.0% = $32,952
+ State A 1,373
Total $34,325

B-Cost to State B at Year 0 = $21,000 x 95.2% = $19,992

% of units after Year 0 to State B = $\frac{3,000-2,000}{1,025}$ = 97.6

Cost to State B after Year 0 = $13,325 x 97.6% = $13,005

Total cost to State B = $19,992 + $13,005 = $32,997
+ State A = 1,328
Total $34,325

C-(2,000 x $10) + (200 x $11) + (200 x $12) + (200 x $13)
+(200 x $14) + (200 x $15) = $33,000
+ State A = 1,325
Total $34,325

D-Cost of facilities located in State B at Year 0 = $20,750

% of those facilities needed by State B = $\frac{2,000}{2,100-50}$ = 97.6%

Total cost at Year 0 for State B = $20,750 x 97.6% = $20,252

Cost to State B after Year 0 = $13,005 (same as growth share)

Total cost to State B = $20,252 + $13,005 =	$33,257
+ State A =	1,068
Total	$34,325

In rebuttal to TURN's proposed growth share allocation method Pacific argues that the method gives vested property rights of specific resources to the various states, an action which is not consistent with the operation of the company system for several reasons. It attempts to take from states which supply electricity, such as Wyoming, the benefits of some of the company's low cost hydroelectric facilities. If applied state-by-state, the growth share system would give all of Pacific's hydroelectric facilities and purchased power to Washington, Oregon, and California and a very minimal amount to Montana and Wyoming. However, the company would still require Wyoming to share the benefits of its coal-fired generation to make up for the deficits in capacity that exist in Washington, Oregon, and California.

Pacific claims that establishment of a property right to consumers cannot be done under past U.S. Supreme Court decisions and cites Board of Public Utility Commissioners v New York Telephone Company (1926) 271 US 23. In that case the Court determined that the customers of a utility pay for service not for the property used to render it. The Court stated "by paying bills for service (customers) do not acquire any interest, legal or equitable, in the property used for their convenience or in the funds of the company. Property paid for out of moneys received for service belongs to the company just as does that purchased out of proceeds of its bonds and stocks." Further, Pacific claims that the issue as to whether newly constructed or acquired utility property or power supplies should be allocated to specific customers, thus providing higher rates for new customers and lower rates to old customers, has been carefully considered by the Federal Energy Regulatory Commission (FERC) and its predecessor the Federal Power Commission. In Idaho Power Company (1978) 25 PUR 4th 91, the Commission established that all customers of a regulated utility should share equally in costs unless there is evidence that specific facilities were constructed expressly for the benefit of identifiable customers. Pacific states that in addition to the judicial and regulatory commission decisions on property rights and utility operations and the allocation of utility property, Public Law 88-552 affects Pacific's electric operations. This law establishes priorities for nonfirm secondary energy available from the Bonneville Power Administration (BPA). The law grants Pacific Northwest states[4/] a preferential right to BPA secondary energy. BPA has applied this provision by restricting the amount of energy it will sell to utilities to that amount required to service loads within the Pacific Northwest. But

---

4/ In Exhibit 45 Pacific's witness Deesen describes the Pacific Northwest as "(1) the region consisting of the states of Oregon and Washington, the state of Montana west of the Continental Divide, and such portions of the states of Nevada, Utah, and Wyoming within the Columbia drainage basin and the state of Idaho as the Secretary may determine to be within the marketing area of the federal Columbia River power system, and (2) any contiguous areas, not in excess of seventy-five airline miles from said region, which are a part of the service area of a distribution cooperative which has (i) no generating facilities, and (ii) a distribution system from which it serves both within and without said region. The northern California properties of the Company are thereby excluded as being a part of the Pacific Northwest."

Pacific concedes that because it is an integrated system there is no way of knowing which electrons produced by BPA are used in which state of the system. Even so, BPA would not knowingly sell energy to California if that part of California which makes up the Pacific system were a separate entity unless several criteria had been met prior to the sale. These criteria make it mandatory for BPA to sell the power to Pacific Northwest users first and to other users second.

Pacific claims that the customers of the integrated system in each of the five states served receive many benefits from the integrated system approach. Customers in each state receive access to the hydroelectric, purchased power, and thermal resources of Pacific on an equal basis. The integrated system allows Pacific to schedule its resources as available to meet the loads of all of its customers and provides a flexibility of scheduling which results in use of the lowest cost resources available. Pacific can obtain a quantity of reserves from a diversity of sources in the five-state system, thereby operating on a lesser reserve requirement than could a smaller or isolated one-state system. Pacific believes that specific benefits received by California customers come in the form of economies produced by central administration not available to a small company, access to energy avilable from BPA, purchased power from other sources, Pacific's Washington and Wyoming coal resources, and assistance from other jurisdictions in supporting the revenue requirement applicable to the cost of transmission lines.

Pacific asserts that the present allocation method assumes that each state has access to the system with no state having a preference to any part of the system; therefore, their allocation method is the only one consistent with the actual operation of Pacific's facilities.

Pacific claims that if the Commission were to adopt the TURN allocation proposal, it would be necessary to keep track of the available power and the cost of generating such power in order to schedule its facilities to meet the specific daily and hourly requirements of each state in the system. Pacific cites the example of assuming California to have rights to a specific percentage of a given plant. If that is the case, then California should have to depend on that percentage of that plant for its needs. If for some reason that plant were to go out of service temporarily, a decision would have to be made as to how California's load could be met from its share of any other plants assigned to California. This would destroy the flexibility of the present system and require Pacific to spend millions of dollars to provide the instrumentation and facilities needed to monitor the deliveries of power from each assigned generating plant to each of its five state systems.

Even if the Commission were to accept the growth share method of allocation, Pacific has several problems with the manner in which TURN's witness Wells applied the procedure. In order to understand Pacific's criticism of that application, a background as to how Pacific developed as a five-state integrated system is in order. That background is contained in Exhibit 1 of witness Geiger for Pacific:

> ". . . Initially, its principal properties were in the Yakima Valley and Walla Walla, Washington; the Pendleton area, the Mid-Columbia area adjacent to The Dalles and the Astoria area in Oregon. Subsequently, the Company acquired a number of small utilities contiguous to its service areas and over the years these properties were integrated into the Company's system by construction of transmission lines and through transmission lines of other private companies, the Bonneville Power Administration and the United States Bureau of Reclamation.

In 1947, Northwestern Electric Company, an affiliate providing service in the City of Portland and certain areas bordering both sides of the Columbia River, was merged into the Company. In 1954, the properties and service areas of Mountain States Power Company were acquired through merger.

"The Mountain States service territory in Oregon included urban and rural areas in the Willamette Valley in Benton, Linn, Lane and Marion Counties; three Oregon coastal areas, including Tillamook, Northern Lincoln County and a substantial portion of Coos County, including North Bend, Coos Bay, Coquille and Myrtle Point. The Tillamook properties subsequently were sold to another agency also serving that area. The Mountain States service area also included Sandpoint; Priest River and vicinities in Idaho; The Flathead Valley in Montana; and, a substantial part of the state of Wyoming. Beginning in 1955, several other small systems in Wyoming were acquired through merger and acquisition. In 1961, the California Oregon Power Company was merged into the Company, and the service areas were thereby extended to include portions of southern Oregon and northern California."

Further information on the development of Pacific can be quoted from Exhibit 45 of Pacific's witness Deesen.

"Prior to June 1961, the Company's present electrical system in California was owned and operated by the California Oregon Power Company (COPCO). It became apparent in the late 1950's that COPCO would be unable to meet the load growth of Northern California and Southern Oregon loads except through the development of higher cost hydro and thermal plants. COPCO was not a customer of the Bonneville Power Administration (BPA) and was unable to purchase low cost energy from BPA. One of the major benefits to California customers of the merger with the Company was gaining access through the three-state integrated system

> to the 'requirement contracts' with BPA that guaranteed the Company a power supply equivalent to the difference between the Company's total load and its critical hydro energy capability in the Pacific Northwest region."

Pacific claims that chaos could result if each of the other four states in its system took the approach that TURN is taking in California, which is in Pacific's words, a sharing and allocating of costs on the basis most favorable to the state involved while requiring other jurisdictions to share equally in the transmission costs required to deliver power to that state. Pacific sees each state, in turn, preempting for itself the most favorable power source within its borders or that which was allocated to it in 1968. For instance, Oregon and Washington could argue that since they were receiving energy from BPA, some of the Mid-Columbia projects, and Pacific's Lewis River project prior to the merger with COPCO which served California, Oregon and Washington would be entitled to retain such energy to the exclusion of California. The Mid-Columbia hydroelectric projects which were owned and operated by public utility districts in 1968 have withdrawn some of their reserved shares of power which were available to Pacific in 1968. That reduction amounts to over 247 MW of capability based on those projects' present installed capacity. Other contracts which were favorable in 1968 have either been cut back or canceled and, therefore, would no longer be available to California even though a percentage of their capacity and production was allocated to California in 1968. Through a careful analysis of the purchased power contracts available to Pacific in 1968 and those remaining in existence in 1979, witness Deesen compiled, in Exhibit 46, a revision of Dr. Wells' data on which his allocation was made. The results of witness Deesen's recapitulation of the energy available to California operations both in capacity and kWh resulted in revisions to Dr. Wells' exhibits which brought the revenue requirement under the growth share allocation almost equal to the revenue requirement that Pacific's method produced.

In summary, it is Pacific's position, as stated in its brief, that "The existing method of allocating the company's revenue requirement which is supported by the company and staff, and adopted by NARUC and every commission in the company's five-state integrated system, is consistent with (1) the actual operation of the company's system, (2) judicial and regulatory precedents, (3) Public Law 88-552, (4) fair treatment of customers in each of the company's service areas, and (5) economic principles."

The Commission staff supports the allocation procedure used by Pacific with some changes as discussed elsewhere in this decision. Through witness Ferraro the staff stated that it was its policy to follow the NARUC electric service allocation procedure. The staff's position on allocations is that a company's investment should be borne commonly by all users of the company's service because when a new generating station is constructed, it is available for service to all customers both existing and prospective regardless of their geographical locations. The staff believes a fundamental principle of ratemaking is that there is no economic justification for a lower price to the customers who happen to live next door to a power plant than for those more distantly located when all customers are part of and benefit from an integrated system. If neither the public nor the utility is to suffer from inconsistent or incompatible actions, a uniform method of cost allocation is necessary for a system operating under several jurisdictions. It is the staff's position that a reasonable method should be agreed upon by the several regulatory jurisdictions and implemented by the utility in each case. The staff believes that any other scheme would result in each state devising its own allocation method always attempting to minimize its share of the total system and, in all likelihood, resulting in the parts not equalling the whole. Also overlooked is the necessity of an integrated system so that all states can benefit from the security and reliability such a system offers. The staff supports the general principle underlying an adequate allocation procedure that each expense should be distributed among the states served by the utility in proportion to the responsibility of each for the incurrence of the expense.

TURN, of course, uses that same principle to support its argument for the growth share method because it is TURN's position that California has not been entirely responsible for the additional plant necessary to serve the growth on the Pacific system but only a portion of it. It is TURN's position that the growth in other states, which is relatively greater than California's, has caused Pacific to build more expensive plants than would be required to serve the additional growth in California.

Nicholas Tibbetts (Tibbetts), for Assemblyman Bosco, supports the TURN-proposed allocation procedure and, in fact, would prefer to see an application of the Edwards method which would allocate all California hydro to California and make up the differential needs by the average cost on the rest of the system. Tibbetts points out an interesting possibility which focuses on the problems that can occur by excessive growth in one state as compared to another. This illustration has to do with the projected future of Pacific's Idaho customers. Pacific serves approximately 8,000 customers in Idaho which is about 25 percent of the number served in California. According to Pacific's witness Reed, Idaho relies 100 percent on purchased power contracted with Washington Water

Power Company. Reed pointed out that rates are considerably cheaper in Idaho compared to other states in the Pacific system. However, that favorable contract is due to terminate in January 1981 and Reed testified that there may be a time when Idaho will become a part of a six-state integrated system if Pacific cannot continue serving through Washington Water Power Company. Thus, if Idaho enters the system, it will come in resource poor. That is, it will enter without any plant generating capacity but immediately add to the system demand. This addition, plus current growth patterns of the system will result in additional high cost capacity and power to be obtained some way by Pacific. This would further erode the California hydro capacity and the low-cost purchased power that California now enjoys. It is Tibbetts' position that Idaho, with the cheapest rates in the entire system, although not being a part of the system, will not make any contributions of generating plant capacity or supply if it gets dumped into the integrated system. And California and the four other states will therefore subsidize Idaho's entry. California will do so by reducing its claim to a proportion of its hydro capacity and pick up the difference in more expensive thermal units. Such a mix would accelerate the increases in cost to California putting it at a further disadvantage. The impact would be felt by California customers in the form of increasing electrical rates with those rates increasing at a greater rate than California's growth in demand and consumption would require if it were not for Idaho coming into the system.

California Farm Bureau Federation (Farm Bureau) takes the position that the Commission should adopt the request of the Farm Bureau in its opening brief filed after the close of hearings in 1979; it requested the Commission institute an investigation on its own motion into the issue of proper interjurisdictional allocations for Pacific and that the utility should be directed to present a complete showing on the effects of allocating California hydro to California customers (Edwards method) and of allocating recent additions to generation and fuel costs on the basis of incremental demand between jurisdictions. Farm Bureau renews that request in its brief filed June 16, 1980. In the meantime, Farm Bureau urges the Commission to adopt the growth share allocation method even though Farm Bureau claims that it does have some flaws. Farm Bureau suggests that in the long run the Commission should assume an integrated operating system which continues to use BPA power and other purchased power by displacement and that costs should be allocated rather than megawatts or megawatthours as done by the growth share method. Nevertheless, Farm Bureau sees the underlying calculations in the growth share method as a starting point for a better, more current, and effective allocation method. Farm Bureau believes that if the Commission does not feel comfortable with going back to 1968 as a base year then a more recent year could be adopted. In any event Farm Bureau urges the Commission to move forward and reform the jurisdictional allocation method currently applied to Pacific's California operations and that in the interim a modified version of the growth share method should be adopted. Further, Farm Bureau urges that in Pacific's next rate case, Pacific and the staff should be required to present new alternatives to allocations which can be fully explored at that time.

Allocations - Discussion

Although Tables 1 and 2 indicate Pacific's system kilowatthour usage per customer is increasing at a constant rate (17 percent from 1968 to 1978, the last recorded figures on this record) it has not yet approached the usage per customer in California. The California usage has increased 11 percent in that period compared to 17 percent for the system. Does this have any effect on adopting an allocation procedure which would reward California for less growth than the system average? There is nothing on this record, and the question was asked of numerous witnesses, that explains why the California usage per customer has been traditionally higher than the system. The system is now catching up to California; in 1968 the California usage per customer was 12 percent more than the system; in 1978 it had dropped to half that, being 6 percent over the system usage. A great deal of discussion during the hearings centered about the relationship of the average California usage, the system kWh sales versus California, and California as a percent of those system sales. Chart A graphs the kWh usage for system and California as well as the differential between those usages. It can be seen that the differential stabilized in about 1972 to a difference of approximately 1,000 kWh per customer, per year. Chart B shows the relationship of California kWh sales as a percent of system for 1968 through 1978. That decline has been leveling off slightly, that is, the rate of decrease is decreasing.

With the above data in mind, what happens if the Commission adopts the growth share allocation procedure and the relationships begin to change over the next few years with California reversing its trend and growing more rapidly than the system? In that case it would seem that California would be stuck with its choice and the other states would reap the benefits of the growth share method.

What would be the proper method of applying the growth share system relative to the time frame involved? TURN goes back to the rate case of 1968 and works from there in one jump to the rate year in this case, calendar year 1979. In Decision No. 87071 dated March 9, 1977 in Application No. 56395, the last general Pacific rate increase proceeding in California, we granted rates based on results of operations which were allocated to California using the integrated system method. We do not believe it would be fair to go beyond the rate year used in that decision as a starting point for application of the growth share method, i.e., the 12 months ended September 30, 1975. Therefore, in lieu of the data TURN offered we requested our staff to duplicate to the best of its ability the growth share method used by TURN but apply it to the rate year ended September 30, 1975 as a starting point. They have done this and the result is shown on Table 4, infra; the staff, Pacific, and adopted results are shown also for comparison. Appendix H shows, for illustrative purposes, how the growth share method would be applied to test year 1979.

PACIFIC POWER AND LIGHT CO.

Source: Tables 1 and 2

CHART A

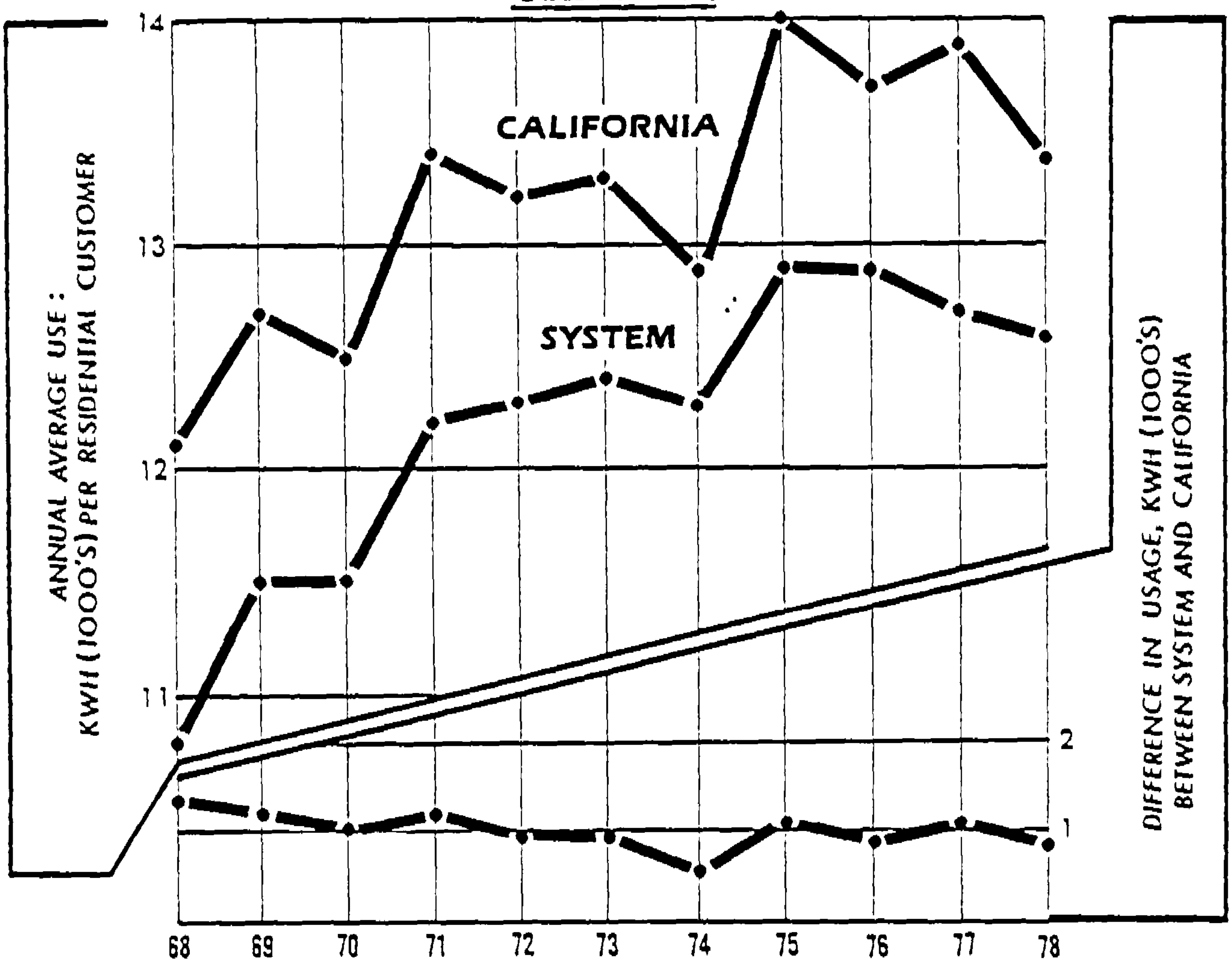
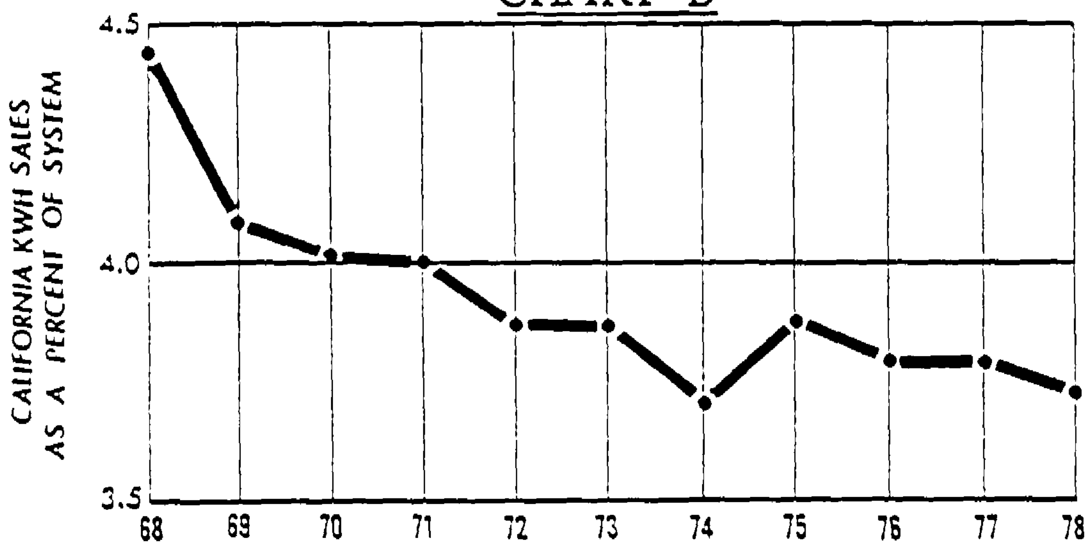


CHART B



In the TURN method, is there a problem with the allegation that the method allocates property rather than costs? The answer to this lies in analyzing the purpose of an allocation procedure. If the TURN method allocates facilities then so does the integrated system method when it allocates on a direct basis. When direct allocation cannot be applied, the integrated system method determines the percentage of California operations to system and applies that ratio to the total system plant cost to obtain the California plant cost. The TURN method does nothing different from that. It allocates different parts of the system at different rates but those allocations are based on the same end requirements Pacific uses for the relationship of California to system. It looks at that relationship at different time periods rather than at the particular time that the allocation is being made. For example, in this case, as far as Pacific is concerned, everything stopped in 1979, a new system existed and California was a percent of that system. The TURN system would have everything stopped in the rate year 1968, take one step to 1979, and then proceed on an incremental basis year-by-year from 1979 on. Finally, although Pacific allocates 4 percent of all plant costs to California, no one claims that Californians now have a vested right to that plant.

The staff states that a general principle underlying any allocation method is that each expense should be distributed among the states served by the utility in proportion to the responsibility of each for the incurrence of the expense. Both the growth share method and the integrated system method arguably are consistent with this principle. One emphasizes responsibility for new demands placed upon the utility while the other relies upon a more static view of utility operations.

We believe the growth share method has substantial merit in that it seeks to correlate increases in demand with the incremental costs incurred to meet such demand. As proposed by TURN, however, this allocation method has the disadvantage of assuming a direct correlation between demand growth in a particular year and plant additions in the same year. This assumption does not reflect the longer range planning required in the utility business.

Should the fact that a proposed allocation procedure has not been used nor adopted by any other jurisdiction, including the jurisdictions with regulatory authority over Pacific, be a reason to reject the procedure? We believe not. The fairest allocation of costs to California customers which does not unfairly burden customers in other states should be adopted. Allocation procedures should reflect the constantly changing demands and composition of multi-state utility services. On the other hand, it would not serve the interests of Pacific's California ratepayers for this Commission to take unilateral action at this time which would likely be perceived as a shirking of responsibility by California and which might provoke other jurisdictions to seek cost allocation formulas which would minimize their responsibility to cover Pacific's reasonably incurred costs.

Will adoption of the integrated system method of allocation adequately account for the reduction in costs and usage to California which may be brought about by the weatherization incentives program approved in D. 91497? The weatherization program authorized by D. 91497 will not become effective until well into the year 1980. Therefore, the problem need not be resolved in this decision. However, in the next rate case brought by Pacific, we will expect all parties to make recommendations as to whether and, if so, how to pass on the real savings of the weatherization program to Californians. In this regard, we must note that the weatherization incentives program authorized in D. 91497 was modeled on similar programs which have been in place and operating for several years in Pacific's Oregon and Washington service areas. The question of whose conservation is benefitting whom is thus not a simple one.

Is Pacific's argument valid that under the growth share method it would be necessary to set up equipment to make sure that California received the proper percentage of the capacity of each of the installations assigned to it to reflect its share of allocated costs? As stated in answer to an earlier question, we do not believe the growth share method should be considered as allocating specific property to California consumers. We look at it as a method, like other methods, which merely uses units to determine the allocations of plant and expenses, such units reflecting the jurisdictional rate year relationships for a given rate case. We do this with full awareness of the comments of TURN's witness Wells concerning his analogy of a separate "California-Pacific" utility with specific company assets allocated to that utility.

Is it fair for the Commission to approve and adopt at this time an allocation procedure which does not treat the Pacific system as an integrated whole, even though the Commission approved the COPCO/Pacific merger with part of the justification being that an integrated system would be advantageous for California? When the Commission approved the COPCO merger, it did not stipulate that any particular allocation procedure should be used for determining the California results of operations under the merged systems. We believe it is our responsibility to consider changes in allocation procedures when appropriate to reflect the changing conditions of utility systems and subsystems.

How should the choice of allocation methods be affected by this Commission's concern to encourage energy conservation? We see the growth share method as providing a more precise price signal and a more effective conservation incentive to Pacific's customers than does the integrated system method, because the former method allocates the burden of additional operating costs and investments in accordance with increases in demand. Adoption of the growth share method would provide a slightly lesser increase in rates to California customers, but it offers the possibility of increasing rates in other states, where overall usage and consumption per household are growing more rapidly than in California. Creation of the appropriate price signals in other states will require a cooperative effort and is unlikely to be achieved by the unilateral action of this Commission.

What is the relevance to the allocation issue of the fact that Pacific is a multi-state utility? It is only because Pacific is a multi-state utility that this Commission gives serious consideration to allocating costs on other than an integrated system basis. This is because Pacific's multi-state character gives us only limited control, for practical purposes, over Pacific's resource planning and investment decisions. Certainly we retain our authority to disallow the passing through to California rate payers of costs of plant imprudently constructed or of no benefit to California, but sensible regulatory policies should seek to avoid the development of situations where such drastic action is necessary. One such sensible policy would be the development of a cost allocation formula attuned to the current need for energy conservation and the soaring costs of new plant construction.

In view of the long-continuing discrepancy in the rate of growth in demand between Pacific's California service area and the rest of its operations, the need to provide an opportunity for California rate payers to benefit by the fruits of their conservation efforts, and the special character of Pacific as a multi-state utility, we conclude that a substantial change in the method of cost allocation applied to Pacific by this Commission is appropriate and that the growth share method has substantial merit as an alternative approach. We are concerned by the inequities which may result from application of the precise method proposed by TURN, particularly with regard to the year-by-year basis for allocating costs, which falsely assumes that responsibility for each year's increased plant costs are attributable to that year's increase in customer demand. However, this is a matter of detail which could be corrected without abandoning the basic concept of allocating incremental costs in accordance with responsibility for such costs which we preceive to be the essence of the growth share method.

Pacific's present cost allocation method is based upon one which was developed through such cooperative efforts within the framework of NARUC. It was developed at a time when attitudes toward electric demand growth were still strongly influenced by the experience of declining marginal costs. These facts have changed; the era has changed; but the value of working cooperatively through NARUC to achieve an allocation formula which will encourage energy conservation and proper cost responsibility throughout Pacific's service area is undiminished. As a net importer of energy, dependent upon the abundant hydroelectric power of the Northwest and the newly developing fossil fuel resources of the Rocky Mountain region to meet a significant portion of our future energy needs, it would be shortsighted of California to incur the wrath of its sister states by failing to pursue a cooperative course of action.

Despite the effective case presented on behalf of the growth share method and our conviction that such a methodology offers substantial advantages, we will not adopt it at this time. To do so unilaterally, without having consulted with other regulatory authorities having jurisdiction over portions of Pacific's operations, would likely be perceived by those authorities as a well camouflaged but unprincipled effort to shield California ratepayers from their fair share of responsibility to support Pacific's operations - in short, an example of the all too prevalent "pull up the drawbridge" approach to social responsibilities. It would invite each other state to improvise its own cost allocation method to serve its parochial interest in minimizing short-term costs to its citizens, leaving Pacific and all its customers to reap the whirlwind of inadequate return, inferior service, and ultimately higher costs. It would also invite federal intervention in an area traditionally left to the cooperative efforts of state agencies.

We emphasize, however, our conclusion that the growth share method offers a basis for allocating Pacific's costs in a manner appropriate to current needs and conditions. We intend to bring this issue promptly to the attention of the appropriate regulatory authorities with jurisdiction over Pacific, and we have already had preliminary discussions to that end. In addition, we will send to each such authority a copy of this decision together with a transmittal letter seeking the cooperation of these authorities in developing a method of interjurisdictional cost allocation more appropriate to present circumstances. Even in the absence of agreement among all the states, it may be appropriate to adopt an adaptation of the growth share method in Pacific's next general rate application. We will therefore instruct Pacific to provide as part of its next general rate application a proposal for allocation of costs to its California service area based upon a growth share method. The method employed should address the concern about year-by-year allocation discussed previously.

For this decision only, we will adopt Pacific's integrated allocation method as modified by the staff. Upon this basis, Table 4 shows a comparison of the staff's, Pacific's, and the adopted summary of earnings, along with a parallel calculation based on the growth share method described on page 27.

TABLE 4

Pacific Power & Light Company

ESTIMATED SUMMARY OF EARNINGS
Test Year 1979

Item	Staff (A)	Pacific (B)	Growth Share Allocation Method (C)	Adopted (D)
		(Dollars in Thousands)		
Operating Revenues				
Total Operating Revenues	$24,592	$25,386	$24,460	$24,741
Operating Expenses				
Production	6,275	6,351	6,016	6,249
Transmission	778	1,101	790	778
Distribution	1,128	1,128	1,128	1,128
Customer Account	531	531	533	531
Customer Service and Information	210	195	210	210
Administrative and General	1,833	1,933	1,832	1,833
Subtotal	10,755	11,239	10,509	10,729
Book Depreciation	3,191	3,181	3,146	3,191
Taxes Other Than on Income	1,250	1,282	1,230	1,250
State Corporation Franchise Tax	347	349	361	359
Federal Income Tax	469.8	450	490	486
Total Operating Expenses	16,012.8	16,501	15,736	16,015
Net Operating Revenues Adjusted	8,579	8,885	8,724	8,726
Rate Base	86,483	86,601	86,458	86,483
Rate of Return	9.92%	10.26%	10.09%	10.09%
Total Amount of Increase	5,493	6,287	5,361	5,642
% of Increase in Revenues Excl. Special Sales and Other	32.4%	37.1%	31.7%	33.3%
% of Increase in Total Revenues	28.8%	32.9%	28.1%	29.5%

Expenses

Pacific and the staff were the only parties to the proceeding to make estimates of expenses with the following exceptions by the staff:

1. Exclusion of the Libby, Montana generating facility expenses. These were eliminated because in the staff's opinion it is a standby facility to be used as a peaking unit if needed to serve the Libby, Montana service area. The staff eliminated $6,000 of operating expenses which were allocated to California.

2. Disallowance of research and development costs associated with the Liquid Metal Fast Breeder Reactor associated with the Trojan Nuclear Power Plant. This disallowance amounts to $15,000 which is allocated to California from Pacific's contribution of $306,000 to the reactor. Payments to this project by Pacific have not been made since 1977 due to the failure of Congress to act on the project; congressional action may not occur during the test year and beyond. For this reason, the staff excludes the expense.

3. The allocation of transmission expenses solely on a demand basis. The staff recommends that Pacific adopt the demand allocation method as used by other California utilities or make an appropriate presentation for a different type of allocation. In lieu of that, the staff recommends that transmission expenses be allocated 100 percent on demand.

4. Use of actual budget amounts for outside services. Pacific estimated outside services by trending, whereas the staff believes the actual project amount should be used. The staff made a $14,000 adjustment in this expense for California.

For purposes of this proceeding, Pacific did not challenge the staff adjustments outlined above. They will be adopted for purposes of expenses in the results of operations used herein.

TURN, through its witness McCabe, wanted to do what is known as a budget variance analysis. According to TURN, such an analysis provides the means to adjust a future budget to reflect the expense levels that will most likely occur. This is done through a quantity and quality variance analysis which adjusts test period estimates proportionately by the relationships of actual achieved results to budget estimates for a given historial period. TURN requested Pacific furnish items necessary to complete such an analysis; the response of Pacific was not acceptable to TURN because of certain restrictions on the use of the material. TURN could not accept the conditions, did not pursue it further, and no analysis was made.

Rate Base

Again, the staff and Pacific were in general agreement on the items and the amounts to be included in rate base. The major adjustments recommended by the staff were:

1. A $1,100,000 system adjustment to the Centralia Plant precipitators of which $44,000 is allocated to California.
2. Removal of the Libby, Montana generating facility from rate base as discussed previously under expenses.
3. As a result of the recommendation of the staff accountant, the staff disallowed preliminary surveys and investigations

> associated with construction work in process. This included $808,000 representing preliminary survey and investigation, miscellaneous work in progress, miscellaneous deferred debits, and other miscellaneous items. Also excluded was $68,000 from electric utility plant in service related to allowance for funds used during construction. Pacific did not contest the above exclusions.

We will adopt them for purposes of the results of operations in this proceeding.

Under cross-examination by TURN, Pacific witness Reed revealed that a new transformer scheduled for installation at the Del Norte substation was being delayed because of a strike at Westinghouse, the supplier of the transformer. $827,000 for that project was included in Pacific's rate base estimate for the year 1979 since the transformer was expected to be installed in 1979. Because Pacific's rate base is calculated on an average of beginning and ending balances for the rate year, $413,500 would be attributable to rate base for this project. The record is unclear whether Pacific will have the transformer installed and operating by the end of 1979. Therefore, we will not make the correction.

Tibbetts alleges that the Washington State Utilities and Transportation Commission determined that Pacific's working cash requirement is negative. The Commission staff exhibit established that estimated working cash allowances are derived by using the FERC method. The staff also performed a working cash analysis as recommended by its standard practice U-16 and concluded that since the result of that analysis exceeds Pacific's estimate, no adjustment should be made to the Pacific figure. We will not make an adjustment to working cash.

Tibbetts pointed out that deferred income taxes associated with accelerated depreciation should be included in Pacific's capital structure because such an inclusion was made in results of operations used by Pacific in the State of Washington. Pacific replied that this was done because Washington permitted normalization of the tax benefit associated with accelerated depreciation of certain property. In contrast, Pacific's revenue requirement in California does not reflect any deferred taxes created by normalized accounting practices. We will accept the Pacific and staff estimates on this matter.

Other Staff Recommendations

In addition to the above recommendations on expense and rate base adjustments, the staff made the following recommendations on future treatment of revenues, expenses, and rate base, which we will adopt.

1. Include in operating revenues additional imputed amounts for the U.S. Bureau of Reclamation Contract.
2. Discontinue charging institutional advertising and Trojan Nuclear Plant Visitor Center costs to operating expense for ratemaking purposes.
3. Discontinue the practice of taking allowance for funds used during construction on land and capitalizing related property taxes.

Property Tax Savings

There are two property tax matters to be considered in this decision. The first concerns whether Pacific properly accounts for the refunds in California required by Proposition 13 property tax reductions. The staff has reviewed rate reduction filings that Pacific made relative to Proposition 13 and confirms that the reductions required have been accomplished. We adopt the staff report.

The second concerns litigation between Pacific and the State of Oregon regarding asset evaluation for property tax purposes.

That case was recently resolved favorably for Pacific and will result in property tax refunds to Pacific for the tax years 1975-76 and 1976-77, a possible refund for 1977-78, and reductions for subsequent years. The staff recommends that California's allocated share of Oregon property taxes for the test year 1979 be reduced by $32,000 to reflect the lower obligation for that year; Pacific concurs in the adjustment.

However, TURN contends that the proper treatment of the refunds is to pass through to California customers their full share of the amount Pacific will recover because California rates have been based on the taxes estimated for the year ended September 30, 1975. Specifically, TURN recommends that $32,000 for each of the three tax years, a total of $96,000, should be treated as revenue to Pacific in the 1979 test year and any rate increase granted should be reduced by that amount.

Many times we have faced the situation of a utility's reducing its expenses through the efforts of its management. We believe in this case that the staff approach is correct and should be adopted and TURN's proposal should be rejected. We do not expect a utility to come running to the Commission for a rate adjustment each time its expenses may be more than anticipated in a given rate setting case. A utility is granted only the opportunity to make its anticipated rate of return, it is not guaranteed that return. Conversely, if a utility accomplishes a reduction in an anticipated expense that was found reasonable by the Commission for the purpose of setting rates, the Commission should not step in and order a refund unless such a reduction was anticipated. To do so would soon discourage utilities from searching for ways to cut costs and be contrary to the intent of Section 456 (re Pacific Tel. & Tel. (1977) 83 CPUC 230). It is, however, our responsibility to reflect properly the expenses anticipated, as we may find them to be reasonable, in a current rate case; by adopting the staff proposal on this issue we will accomplish that in this proceeding.

Affiliate Adjustments

Pacific owns a two-thirds interest in the Jim Bridger coal-fired generating plant in Wyoming. Coal for that plant is supplied by the Bridger Coal Company, which is two-thirds owned by Pacific Minerals Inc. Pacific Minerals Inc. is a wholly owned subsidiary of NERCO Inc., which, in turn, is a wholly owned subsidiary of Pacific. The remaining one-third interest in the Bridger Coal Company and in the Jim Bridger Generating Plant is owned by Idaho Power Company. Therefore, Pacific is purchasing its coal supplies for the plant from a subsidiary company under its control. TURN claims that it is well-established law in California that the prices a utility pays for purchases from an affiliate can provide no greater return to the affiliate than that allowed for the utility itself and cites Pacific Telephone and Telegraph Company v PUC (1965) 62 Cal 2d 634 and Decision No. 78851 (1971) 72 CPUC 327 and City of Los Angeles v PUC (1972) 7 Cal 3d 331, 334.

At the request of TURN, Pacific presented exhibits based upon estimated 1979 data which duplicated an exhibit in Washington Utilities and Transportation Commission Cause No. U-78-52, which was decided June 4, 1979. That decision adjusted the coal prices paid by Pacific to the Bridger Coal Company resulting in a reduction in the cost of service in the Washington case. The exhibit put in by Pacific shows that if one were to follow the Washington case methodology, the resulting reduction in California fuel expense would be $25,600. No evidence was presented on the record concerning the appropriate return for the Bridger operation considering the special characteristics which may be inherent in a coal mine operation. TURN's witness McCabe testified that in his opinion the adjustment should range anywhere from $76,800 to $98,000 depending on how rate base and rate of return are determined. We adopt the $25,600 as the appropriate adjustment in this case.

Rate of Return

Pacific, through its witness John H. Geiger, senior vice president-finance, recommends an overall rate of return of 10.26 percent; this would produce a return on common equity capital of 14.50 percent. The staff recommends an overall return of 9.92 percent which reflects a 13.50 percent return on equity. There is little difference between the Pacific and staff-recommended capitalization ratios and cost of long-term debt and preferred stock. (See Table 5.) Pacific agreed that for purposes of this proceeding it would accept staff's proposals on rate of return with the exception of return on equity.

Pacific's contention that 14.50 percent is a reasonable return on common equity is based on a mathematical rate of return model known as the "Pacific Model". Pacific uses the model to determine the rate of return required to support a specific growth rate applicable to common stock equity capital and enable Pacific to sell stock at a price that will not reduce book value per share. The model involves certain aspects of the discounted cash flow approach to developing rate of return recommendations. It is not purely mechanical but requires the use of certain key assumptions based on the judgment of Pacific personnel. The final formula in the model calculates return on equity capital using four independent variables: the growth rate in equity capital, the dividend payout

TABLE 5

Pacific's Requested Rate of Return

Component	Capitalization Ratios	Cost	Weighted Cost
Long-Term Debt	54.00%	7.76%	4.19%
Preferred Stock	10.00	8.45	.85
Common Stock Equity	36.00	14.50	5.22
Total	100.00%		10.26%

Staff's Recommended Rate of Return

Component	Capitalization Ratios	Cost	Weighted Cost
Long-Term Debt	53.28%	7.84%	4.18%
Preferred Stock	11.78	8.65	1.02
Common Stock Equity	34.94	13.50	4.72
Total	100.00%		9.92%

ratio, the ratio of net proceeds to market price prior to announcement of a new offering, and the market capitalization rate, also known as the common stock investors' discount rate or expected return. The formula is very sensitive to the last factor, the market capitalization rate, which is the sum of the dividend yield and the expected growth in dividends per share. Pacific chose two values, 13.5 and 14.5 percent, for that factor and kept the other three constant to calculate a low and high estimate for return on common equity. That produced 14.04 and 15.12 percent, respectively, about one-half percentage point above the assumed values for the market capitalization rate. Pacific recommends 14.50 percent, the approximate average of the 14.04 and 15.12 percent. Pacific claims the 14.50 percent is in line with Commission Decision No. 90405 dated June 5, 1979 in San Diego Gas & Electric Company (SDG&E) Application No. 58607. Witness Geiger stated that SDG&E and Pacific are similar with respect to their common equity return requirements and pointed out that the staff listed SDG&E among 20 companies it considered comparable to Pacific. Like Pacific, SDG&E has its first mortgage bonds rated Baa by Moody's which is the lowest investment-grade bond rating. Pacific claims the 14.50 percent granted SDG&E, which also provides an after-tax interest coverage of 2.7 times, is appropriate for Pacific as well as SDG&E.

Edwin Quan, a financial examiner on the Commission staff, testified that an overall 9.92 percent rate of return is proper for Pacific. That return would provide a 13.50 percent return on common equity and 2.4 times interest coverage. Witness Quan stated that a fair and reasonable rate of return results from the consideration of many factors and that one cannot rely solely on definitive formulas or precise mathematical calculations. In his opinion, judgment is the determining factor in the final analysis with due consideration of the requirements of the individual utility. The staff presented a study containing 13 statistical tables developed to assist it in making a final judgment. Some of the tables compared the operating results of Pacific for the years 1974 through 1978 with comparable results for ten combination gas and electric utilities and ten electric utilities which the staff believes are regulated public utilities having business and financial risks similar to those of Pacific. The comparisons show that Pacific's earnings on total capital and times-interest earned were lower than the average of the comparative groups, whereas its earnings on equity were higher than the other utilities. The common equity ratio for Pacific and the comparative groups was about the same. In another comparison, Table 11, Exhibit 16, the staff set forth the results of a survey of recent decisions on two combination and six electric utilities. The simple average allowance on common equity for the six electric utilities was 13.08 percent. In its opening brief, Pacific updated the comparison with a more recent decision on Portland General Electric Company and the addition of data on the last decisions of SDG&E and Cleveland Electric Illuminating Company, two companies the staff said are comparable to Pacific but were not listed on Table 11. With that revision the simple average allowance on common equity rose to 13.59 percent.

TURN recommends that the stipulated 13 percent return on equity recently granted in the State of Washington in Cause No. U-78-52 dated June 4, 1979 be adopted for Pacific in this decision. However, TURN maintains that in no case should the equity return exceed the staff recommendation of 13.50 percent. Additionally, TURN recommends a reduction in the overall adopted rate of return of .06 percentage points to account for TURN's recommendation concerning the conservation program discussed elsewhere in this decision. As an example, if the Commission were to adopt the staff recommendation, the overall return should be reduced from 9.92 percent to 9.86 percent.

Farm Bureau maintains that the evidence presented by Pacific does not support a 14.50 percent equity return; it claims Pacific did not properly analyze the risks faced by Pacific or the returns earned by similarly situated utilities. Farm Bureau believes the allowance of 14.5 percent granted to SDG&E in Decision No. 90405 should not serve as a criterion for Pacific. That decision recognized that SDG&E is facing some particularly difficult problems as a result of the disapproval of its Sun Desert Project, interest coverage shortfalls, and, particularly, high rates of growth. Farm Bureau believes Pacific is a relatively low risk investment because its electric operations are fairly large, it operates in six states, and estimated 1979 total sales will be nearly 23 billion kWh. Also, it is not subject to one regulatory commission, its resources are low-cost hydro and base load coal plus a small amount of nuclear, it is insulated from oil and natural gas price increases, it owns and mines much of its coal requirements, and is a diversified company with water and steam system operations. Also, Pacific has substantial mining, mineral, and telephone utility subsidiary company holdings.

In rebuttal to the staff proposal, Pacific criticized the staff's rate of return witness as lacking the required basic knowledge of Pacific's operations and financial makeup to form a reasoned opinion as to the return necessary for Pacific. That criticism ran the gamut from a lack of knowledge of what states Pacific operates in and the types of customers it serves to unfamiliarity with Pacific's load growth projections and financial requirements over the next five years. On the other hand, the staff criticized Pacific's approach to rate of return as one which puts too much reliance on a mathematical model that, in witness Geiger's words, "is intended to develop the rate of return that will enable the company to sell stock at a price that will not reduce book value per share." The staff views this approach as contrary to long-standing Commission policy that rate of return is a matter of judgment and not merely a matter of applying a mathematical formula.

In this case we criticize Pacific and the staff, the only two parties to present adequate evidence on which we can make a judgment. As for Pacific, the model it uses is very sensitive to the value one chooses for a market capitalization rate. If that factor can be legitimately chosen with a range of one full percentage point and thereby produce an estimate of that same range, there appears to be a question of objectivity, something that one should be able to look to as an inherent advantage of a formula approach. As for the staff, we believe some additional rationale should be given for the rate of return values chosen other than that the staff reliance on the "Hope Natural Gas case" and "In the final analysis, judgment is the determining factor; consideration must be given to the requirements of the individual utility." (Exhibit 16, page 4.) Indeed, it appears the data most relied on by the staff are contained in Table 11 of Exhibit 16. Witness Quan stated, "It is my opinion that my recommended earnings allowance on common equity of 13.50% is within the range of those shown on Table No. 11." (Exhibit 16, page 5.) That table was updated by Pacific with no comment from the staff or other parties. As previously noted, the update raised the average return on common equity by about one-half percentage point.

For purposes of this proceeding we will adopt the staff rate of return recommendation with the exception of an adjustment to its recommendation on common equity; we will increase that from 13.50 to 14 percent based on the update of Table 11, Exhibit 16. Thus, the following is our adopted rate of return:

Long-Term Debt	53.28%	@	7.84%	=	4.18%
Preferred Stock	11.78	@	8.65	=	1.02
Common Stock Equity	34.94	@	14.00	=	4.89
Total	100.00%				10.09%

Wage/Price Guidelines

The Federal Council on Wage and Price Stability (Council) has issued several price standards to implement the President's anti-inflation program. (See Decision No. 91107 dated December 19, 1979 in Application No. 58545 of Pacific Gas and Electric Company.)

For purposes of calculating estimated rate year 1979 expenses, Pacific assumed pro forma employee wage and salary increases of 5 to 7 percent and associated wage-related benefits not exceeding the levels in effect prior to October 1978. Thus, Pacific claims, expenses for wages and wage-related benefits included in its rate year estimates are within the pay standard guidelines.

Pacific used three arguments to show that its requested increase in rates complies with the price guidelines. First, Pacific's most recent California increase was granted in March 1977 but was based on a test year for the 12 months ended September 30, 1975. Since this application is based on the calendar year 1979, a 34.8 percent increase spread over the 51 months between the two rate years equates to an annual increase of just over 7 percent, well within the voluntary guidelines. Second, the Council has agreed to treat Pacific's electric, steam heat, and water utility operations as a separate reporting company for guideline purposes. Under such treatment, Pacific's overall utility increase complies with the Council's standards although certain jurisdictional rates have risen more than others. Also, increases for the various customer classes can be different for different types of service such as electric, gas, and steam, as well as between customer classes within a given service. Finally, the third argument by Pacific is that a 9.5 percent rate increase in California, which would comply strictly with the guidelines on a one-year basis, would allow Pacific only a 3.22 percent return on common equity. It claims this would be inadequate, unreasonable, and confiscatory. Pacific holds that rate applications, in spite of voluntary price guidelines, still must be judged by the standards of state and federal law which prohibit confiscation. Any application of the guidelines which produces confiscatory levels of return would be in violation of Federal Power Commission v Hope Natural Gas Company (1943) 320 US 591.

All three of Pacific's arguments that the guidelines have been considered and voluntarily complied with are persuasive. The rates adopted by this decision will be no more than necessary to protect Pacific's customers from higher than necessary prices, and yet assure that the needs of customers can be met in the future and Pacific's shareholders are treated fairly.

Rate Design

For purposes of the discussion in this section rates are assumed to be those in effect prior to the interim increase authorized by Decision No. 91326 supra, unless otherwise noted. The following are the primary issues concerning rate design:

(a) Should the rate spread be accomplished in this proceeding by allocating to each class an equal percentage of its long run incremental cost (LRIC) or should the Commission move in steps toward the goal of LRIC-based pricing?

(b) Should a fixed customer charge of $2 as proposed by Pacific and the staff be instituted in lieu of the minimum charge based on kWh usage in effect under present rates?

(c) What should the relationships be between the following schedules: lifeline domestic, nonlifeline domestic, general service, and agricultural pumping?

(d) Should the general service Schedules AT-47 and AT-48 be redesigned in accordance with either the Pacific proposal or the staff's?

(e) Should the proposals for the agricultural pumping schedule, PA-20, concerning changes in annual charges and agricultural seasonal periods be adopted?

(f) Should the present Schedule A-32, which is designed for small power customers and has a flat basic or customer charge and a five-block energy charge, be simplified?

(g) Should the street lighting tariff provisions be simplified and split into two schedules, one for company-owned lights and one for customer-owned lights?

(h) Should time-of-use rates be extended?

(i) Should Pacific's recommendations for changing the charges for reconnections be adopted?

(j) Does the type of allocation procedure used to allocate costs to the various jurisdictions affect LRIC ratemaking?

(k) Does the ratemaking adopted in this decision satisfy the federal standards involving aspects of ratemaking as set forth in the Public Utilities Regulatory Policies Act of 1978 (PURPA)?

(l) How do the rates in California compare to Oregon's?

LRIC Study - Pacific based its proposed spread of rates to its customers on its LRIC study, Exhibit 5. Pacific did not provide any embedded or average cost of service data for this record. An LRIC study is similar to a long-run marginal cost study. It attempts to determine the cost per unit of serving incremental load of a given customer class over a future period. The study then develops the revenue by major class which would be generated by charging all rates equal to long-run incremental cost. Such a study usually produces revenue in excess of a utility's requirement as it did in this case for Pacific. This required Pacific to scale the LRIC rates back to produce the desired revenue. Pacific did this by reducing the difference between current revenues and LRIC revenues on an equal percentage for each major class of service. The result of this approach ranged from a high of 39.1 percent increase for residential service to a low of 26.9 percent for large general service of less than 500 kW. Pacific did not exempt the lifeline sales from an increase under its method and also did not calculate agricultural rates based on LRIC. The agricultural group along with a few other small classes was assigned an increase equal to the system percentage increase. Pacific and the staff agree that Pacific's California rates should be based on the use of LRIC. No one challenged Pacific's method of computing the LRIC by customer class. A staff witness on rate design recommended moving immediately through this rate case to the goal of rates based on LRIC. On the other hand, Pacific proposes that the difference between each class' present revenues and its LRIC be applied uniformly in this proceeding. In effect, Pacific's proposal results in small increases for those classes closer to their LRIC and larger increases for classes further from LRIC. Pacific claims its method has the desirable characteristics of avoiding disproportionate rate increases to customer classes; there would be an orderly phasing in of incremental cost of service results, treating each class of customer in a uniform manner. For each class the difference between LRIC and present revenues would be reduced by a uniform percentage and in successive rate proceedings each class' revenue level would be moved progressively into line with its LRIC while at the same time maintaining a predictable continuity in rate spread design. Pacific takes the position that the rate spread proposed by the staff witness would be reasonable but urges the Commission to adopt Pacific's more gradual phase in.

Basic Customer Charge - Pacific and the staff propose a restructuring of the residential service schedule to consist of a $2 basic charge plus a charge in cents per kWh for kWhs used. This proposal is consistent with what we have done in rate design for other utilities in California and we will adopt it.

Rate Relationships - Most of the evidence in the area of rate design concerned the relationships of residential lifeline to nonlifeline, the residential average to the system, and other rate schedules and classes to the system average rate. In addition to the $2 basic charge, Pacific proposed a restructuring of its residential service schedule so that there would be a charge of 2.962 cents per kWh for the lifeline allowance and 3.789 cents per kWh for hours in excess of lifeline. Pacific claims this would maintain the relationship between lifeline and nonlifeline rates which was in effect when Pacific's application was filed in January 1979. When Pacific reduced rates as a result of Proposition 13 and the 1978 Revenue Act, the decreases affected only nonlifeline charges. Pacific's proposal would restore nonlifeline rates to the January 1979 level and then impose the remaining rate increase in a manner that would maintain the lifeline/nonlifeline relationship that existed in 1979. Pacific estimates that if its increase is granted in full, the lifeline rate would increase 35.9 percent over the January 1, 1976 level, the average system rate for the same period 69.3 percent, and nonlifeline rates an average of 126.8 percent.

The staff recommends that the lifeline portion of Pacific's residential rates be increased by an amount equal to the change in the consumer price index (CPI) from April 1975 to March 1979. Staff bases this on the fact that April 1975 marks the last time lifeline rates were changed and March 1979 was the most recent month for which CPI data were available. This would result in a lifeline increase of 31.8 percent. Staff maintains that increasing lifeline rates by an amount smaller than the change in the CPI would give customers a false signal concerning the cost of producing electricity. The staff witness also pointed out that social security payments are tied to the CPI. Pacific points out that if the staff had used more current CPI figures than March 1979, the staff-recommended lifeline increase would be similar to Pacific's.

TURN advocated a very small lifeline increase of only 2 or 3 percent and brought up four arguments in support of its position. First, such action is required, TURN claims, by PURPA and the Miller-Warren Energy Lifeline Act; second, the lifeline rate proposed by Pacific is too high to meet the statutory requirements of low-cost rates for minimum quantities of electricity; third, a small increase in lifeline rates would promote conservation by producing a more steeply inverted residential rate schedule; and, fourth, witness McCabe for TURN suggested it would be appropriate to follow what he terms a "contract theory" in which each customer would be allowed to retain the economic advantages of the types of generation in use when that customer first connected to the Pacific system. For instance, if a person built a house in 1969 and put in electric heat, that person acted upon an analysis of the cost of that installation. Witness McCabe believes, based on that example, that a good argument can be made for low lifeline rates because presumably the lifeline users use the basic generation capability of the company. McCabe believes that lifeline rate increases should be limited to increases equaling a utility's variable costs without consideration of the utility's new capacity costs. Specifically, TURN, through witness McCabe, suggested that the lifeline differential be 25 percent below the system average. Under Pacific's proposal it would be 4.2 percent below the average and under the staff proposal 7 percent below.

Pacific claims TURN's "contract theory" is not valid economically and is not relevant to the lifeline rate determination. Pacific claims electric demand does not know the difference between old and new customers. Further, it should be clear that a change in energy use by customers with similar demand patterns will produce comparable cost changes for Pacific without regard to the chronological connection time of individual customers. Pacific feels it is apparent that McCabe's argument has nothing to do with lifeline rates, which apply to new as well as old customers. Under the McCabe theory, a residential user of 1,000 kWh per month who connected in 1969 would get that entire amount at low cost, while a user with a 500 kWh per month requirement who connected in 1979 would pay much higher rates.

Concerning the Miller-Warren Act and PURPA, TURN believes that taken together, the two Acts reflect a clear legislative policy that electricity required to meet basic human needs must be available to all citizens at an affordable price. TURN points out that throughout the public witness hearings in this case there were many statements indicating that significant numbers of ratepayers simply cannot afford increases in their utility bills. By preserving the current lifeline rate these pressing social needs can at least be partially met. TURN further argues that an increase in lifeline rates would do little to further this Commission's stated goal of encouraging energy conservation though rate design. The reason for this is that most residential customers use considerably more than their lifeline quantity each month. For instance, testimony of Pacific's witness Sloan shows that, on the average, residential customers use at least 200 KWh greater than their lifeline allowance. Therefore, if the Commission wanted to encourage conservation, the amounts above lifeline should be priced considerably higher than the lifeline.

We note here that this is what the Commission has tried to do recently by its rate-setting policy. We will follow that policy in this proceeding and set the average residential rate at approximately the system average rate with the internal relationship of residential nonlifeline to lifeline at about 150 percent. This should promote conservation within the residential class by providing appropriate signals to residential customers concerning the cost of the energy they use as well as providing a penalty for usage over the lifeline amount. The adopted residential rates are shown in Appendix B.

Large General Service - The staff recommended a rate design for Pacific's large general service schedules, AT-48 and the corresponding partial requirement schedule AT-47, which would provide charges for on-peak kWs, no charge for off-peak kWs, and a single energy charge. Pacific proposed a schedule which also contained a basic charge based on the average of the two highest measured monthly demands, either on-peak or off-peak for the current and preceding 11 months. Pacific claims that its proposal is far more equitable for the customers. It appears that the minimum charge proposed by the staff would never be imposed because it is less than the demand charge for the minimum demand customer. The staff conceded that its recommendation may have been based on faulty data. We will adopt Pacific's proposal for these schedules, which are shown in Appendix E.

For Schedule No. A-36, "Large General Service - Optional, 100 kW and Over", both Pacific and the staff are recommending that the rate increase be based upon the LRIC study. We concur with this recommendation. The adopted rates for Schedule No. A-36 are shown in Appendix D.

Agricultural Pumping - Proposals for the general irrigation schedule, PA-20, generated some of the sharpest controversies during the hearings. Pacific proposes a substantial restructuring of the schedule independent of the amount of increase, if any, to be imposed on that schedule as a whole. Staff supports Pacific's proposals. Farm Bureau rejects Pacific's rate spread for the Schedule PA-20 on the ground that the increase is arbitrary because the lack of LRIC data required Pacific to lump the smaller classes together and give them a system average percentage increase. However, PA-20 did not receive the average 34.8 percent because an arbitrary formula for outdoor area lighting, private street and highway lighting, and airway and athletic lighting resulted in lower than average increases for those classes; and the difference was made up by the agricultural PA-20 schedule by giving it a 40 percent increase.

There are two significant areas of change proposed by Pacific. First, the concept of the "irrigation season" will become much more critical. The current schedule defines the season as March 1 to October 31; Pacific proposes substitution of the phrase "meter readings March 27 through November 27" as the agricultural irrigation season. The winter season definition would be correspondingly changed to the rest of the year. Also, Pacific proposes rates which will vary a great deal by season. Energy charges will be roughly doubled in the winter season for instance, and winter demand charges will be assessed monthly in addition to a regular annual charge. Under the new system much of the March consumption could be billed at the high winter rates depending on the date meters are read. For instance, if a customer began irrigating March 1 and the billing cycle called for reading that customer's meter on March 26, a great deal of consumption would be billed at high winter rates. A neighbor, with a similar consumption pattern but a March 28th reading date, would pay much lower rates and neither might know the true reading date. Many farmers testified that the start of the irrigation season was in March and that accurate billing is critical to them. Farm Bureau believes strongly that all consumption occurring on or after March 1 should be at the on-season or lower rate. Obviously, not all meters can be read on March 1 without some automatic device that will do the reading. The ALJ suggested that perhaps postcard meter reading could be employed and requested the advice of the parties on the idea. Farm Bureau endorsed it and Pacific opposed it. Under such a program agricultural customers might read their own meters on March 1 and mail the result to Pacific by a prearranged, preprinted postcard. Pacific could read meters in its normal fashion but would know what consumption occurred between March 1 and October 31, the current season, by combining actual and postcard readings. The postcard arrangement appears to result in more fair and equal billing if large seasonal differences may occur due to the change in meter reading dates.

The second change proposed by Pacific is a dual one and would institute an annual demand charge in place of the current monthly demand charge and would reduce the energy blocks from five to two. Those changes would most seriously affect customers who pump for only two or three months. They would pay an annual demand charge under the proposal equal to about six months of current monthly demand charges. This change could result in large increases for many farmers. Although the number of blocks would be reduced, the declining block aspect of the rate structure remains. Currently, it ranges from 2.49 cents to 1.22 cents. The proposal is to have it range from 2.60 cents to 1.67 cents over only two blocks instead of five. However, the break between the two blocks would be

14,000 kWh per month. This would result in a substantial increase for customers who use 14,000 kWh and less. Presently the 2.49 cents applies up to 1,500 kWh for example, but under the proposal the 2.49 cents would be 2.60 cents and apply all the way up to 14,000 kWh.

Farm Bureau points out that the wholesale redesign of the schedule makes it nearly impossible to determine in advance whether the actual adopted rates embody the percentage increase supposed to be borne by agriculture. In the event there is an increase in the agricultural rates, Farm Bureau urges that each element in Schedule PA-20 be increased by an equal percentage.

Public witness testimony at the hearings indicates that irrigation power by electricity is a critical element in the economics of hay and pasturing in California agriculture. This activity is a very important segment of the rural economy in general. Many witnesses testified that current operations cannot absorb increases of the magnitude of 60 percent or even 45 percent as shown in some exhibits on this record. Testimony indicates that Pacific customers in California are producing for the same market as farmers in Pacific's Oregon territory. Farm Bureau's position is that the Commission should not put California customers of Pacific in an uncompetitive position with Oregon customers.

Edwards objected to the annual charge in the PA-20 schedule. His objections prompted an explanation by a witness for Pacific. The witness explained that since Pacific incurs large fixed costs associated with dedicated distribution facilities that are used to serve such customers, Pacific has proposed that the recovery of those costs not be associated with kWh consumption. For example, if two customers are the same size and have identical fixed distribution costs and one uses energy from its dedicated facility for only two months while the other takes service for eight months, a charge for dedicated service based on kWhs of use will produce unequal payments for equivalent facilities installed to serve the two customers. Accordingly, Pacific proposes the energy charge to recover energy-related costs and the annual minimum charge to recover dedicated distribution-related costs.

Farm Bureau claims that customers will not be given much guidance on how they should alter their consumption patterns in order to reduce future costs. Pacific points out that its proposed revision of the PA-20 rates will give extremely clear signals to customers. Further, Farm Bureau asserted that the rate increase was arbitrary but Pacific points out that this ignores the testimony of its witness Sloan. Sloan explained that the rate spread was determined on the basis of attempting to give a proper signal to customers by reducing the difference between the present revenues and the LRIC of each customer class. He testified that the smaller classes of service were not included in the LRIC study, and Pacific used the formula approach to determine the overall revenue increase for such classes. Pacific believes additional revenue requirements should be recovered from a percentage increase and an increase in the energy charge in order to recognize that all forms of costs incurred by Pacific have increased during recent years. This approach, which is not an arbitrary one, produced total percentage increases for other customers different from that given the agricultural customers.

Pacific concurs that the customer who irrigates in March and has a meter read prior to March 27 will be penalized but Pacific testimony established that its proposal will bill 99.7 percent of the energy used for irrigation at the lower seasonal rates. Even though customers whose meters are read prior to March 26 will indeed have usage during that period billed at the higher winter rates, these same customers, because of their meter reading schedules, will have November consumption billed at the lower seasonal rates. Since irrigation customers have much more consumption in November than in March, Pacific's proposal clearly benefits this group of customers, claims Pacific. Pacific showed that only .3 percent of the irrigation kWhs may be billed at the higher winter rates and believes the additional expense and inconvenience of a postcard system is not justified by the kWhs that would be affected.

We will adopt Pacific's proposals on the PA-20 schedule with the exception that a customer who wishes may institute postcard reading procedures. We will order Pacific to file an advice letter prior to the 1981 season establishing procedures whereby customers who are on the PA-20 tariff may, at their option, read their meters through a postcard procedure as described above.

Small Power Customers - Present Schedule A-32 is designed for small power customers and has a flat basic or customer charge and a five-block energy charge. The first two blocks incorporate a demand component. It was the goal of both the staff and Pacific to simplify this schedule in this proceeding. However, when a simple two-block basic, one-block demand, and two-block energy charge was tested it had a drastic impact on about 35 customers. To moderate the impact and spread it more evenly among the customers, the staff proposes to use Pacific's proposed rate structure except for changes necessary to generate the required revenue. That proposal is shown in Appendix C and will be adopted. The customer charge therein was designed to recover more of the fixed costs of serving seasonal and intermittent customers and customers with low load factors.

<u>Street Lighting</u> - The three major California utilities have begun programs to convert all their company-owned incandescent and mercury vapor street lights to high pressure sodium vapor. The staff recommends that Pacific should consider such a program. The staff also recommends that central computerized records be kept on the number, size, and type of lamps in Pacific's system so that information regarding lamps in service is readily available. The staff believes that Schedule LS-57, which covers street lighting, is too complex. It includes customer-owned lights as well as company-owned lights. In staff's opinion the two types should be treated differently since the former involve energy only and the latter include installation and equipment costs. For this reason, the staff recommends that the present LS-57 tariff be divided into two schedules; one schedule would be for company-owned lights and the other would be for customer-owned lights. This would follow the general schedule format of other major utilities. The staff maintains that such a restructuring would simplify street lighting tariffs and make them easier to apply and understand. As a further aid to the user, the staff urges Pacific to plot graphs of monthly rates versus lumen size for the various types of lamps so users can easily make comparisons. The staff believes Pacific's method for increasing the street lighting rates in this proceeding by applying a formula to the energy rate only is unduly discriminatory in favor of company-owned lights. In their allocation the staff applied the overall system percentage increase to the energy portion and the inflationary increase to the nonenergy portion of the rates for company-owned lights.

By Resolution E-1899 on August 19, 1980 the Commission approved Pacific's new schedules for high pressure sodium vapor street and outdoor lights and also closed incandescent, mercury vapor, and fluorescent lights to new installations. Because this action removes the reason for inflationary increases to the nonenergy portion and the new sodium vapor rates are based on present costs, we will apply a uniform cents per KWh increase to all lighting schedules.

Time-of-Use Rates - By Ordering Paragraph 2 of Decision No. 85559, as revised by Decision No. 86543 issued March 16, 1976 and October 26, 1976, respectively, in Case No. 9804, Pacific was ordered to file specific time-of-use tariffs for customers with demands greater than 500 kW. Pacific has complied with another section of that ordering paragraph by instituting time-of-use rates for all customers with demands greater than 1,000 kW. This was done by creating Schedules AT-47 and AT-48. To comply with the other provisions of the ordering paragraph cited, Pacific has submitted in this proceeding revisions to Schedules AT-47 and AT-48 which qualify all customers with demands greater than 500 kW. The staff agrees with Pacific that the current rate case is the appropriate time to extend the time-of-use rates. Also, the staff believes that designing a separate rate schedule for demand between 500 and 1,000 kW is unnecessary. The staff claims that any differences in costs can be reflected in different customer or minimum charges and in voltage discounts as demonstrated by Pacific in their rate design exhibit. We will adopt those schedules; they are shown in Appendix E.

Reconnect Charges - Pacific proposes to increase its reconnection charges from $5 to $15 during regular office hours and from $8 to $30 at other times. Witness Sloan for Pacific testified that the great majority of reconnections result from prior termination for nonpayment. It would appear from the record then that some customers who may not be able to pay their regular bills in the first place will be faced with higher reconnection charges, may find it difficult to raise the reconnection fee and, therefore, be denied power. TURN suggests that Pacific be required to accept payments in four equal installments. We find this to be a reasonable proposal with the modification that instead of four equal installments, we will order the payment to be accepted at a rate of $7.50 per installment; therefore, two installments would pay the charge of $15 and four installments the charge of $30.

LRIC Ratemaking and Allocation Procedures - One thing which none of the parties brought up during the hearing is the possibility that LRIC-type ratemaking could be affected by the type of allocation procedure which we adopt in this proceeding. Indeed, the growth share method may amend the type of long-range incremental costs which would be assigned to various customers under the various rate jurisdictions. However, we do not see this as a problem because LRIC ratemaking is done on a system basis and the growth share method ideally assigns additional costs to the various jurisdictions on an incremental basis. Therefore, rates resulting from application of the growth share allocation method may more truly reflect incremental costs assigned to the various customers of a single jurisdiction.

Adopted Rate Designs and PURPA - Title I of PURPA established federal standards involving aspects of ratemaking. Standards (1) through (6) of Section 111(d) were examined in Case No. 9804. Decision No. 85559 dated March 16, 1976 in that case initiated requirements which led to the utilities' filing time-of-use rates for customers above 500 kW and conducting time-of-use experiments for customers less than 500 kW. The decision requires consideration of seasonal and declining block rates. The decision also requires the utilities to experiment with and develop interruptible and automatic load curtailment rates.

Section 101 of PURPA establishes the purposes of Title I of the Act; the purposes are to encourage:

1. Conservation of energy supplied by utilities,

2. Optimization of the efficiency of use of facilities and resources by electric utilities, including capital resources, and

3. Equitable rates for consumers.

The staff believes it is not necessary that all three of these purposes be achieved in any one action by the Commission; rather if any of the purposes are achieved and the others are not negatively impacted, a finding can be made that the purposes of the title are carried out.

Section 111(a) requires each state regulatory authority to consider each standard established by subsection (d) and make a determination concerning whether or not it is appropriate to implement such standard to carry out the purposes of the title. Section 113(a) requires each state regulatory authority to adopt the standards established by subsection (b) (other than paragraph (4) thereof) if the state determines such adoption is appropriate to carry out the purpose of the title. Section 114 requires a determination of whether lifeline rates should be established if a utility does not have them and authorizes lifeline rates as an exception to the federal standard on cost of service (Section 111(d)(1)).

It is the staff's opinion that Commission actions in prior proceedings and the staff proposals in this proceeding satisfy the standards of Section 111 and achieve the purposes of Title I. In certain areas the Commission is moving gradually, such as initiating time-of-use rates with the largest customers. This gradual approach appears consistent with the Joint Explanatory Statement of the Committee of Conference which states, regarding Section 111, that the state authority may decide to partially implement the standards such as moving toward time-of-use rates but not fully implement the standard in that regard.

Not all standards under Section 113 were considered by the staff in this proceeding but Section 113 does not require consideration in each rate case. Rather, it requires each state authority to examine the standards in a hearing within two years after enactment. The standards for the automatic adjustment clause and termination of service are appropriate for separate investigations. The standard for information to consumers is in the process of being implemented by the staff based on Commission orders. A standard for master metering and advertising have been achieved consistent with the purposes of Title I.

We believe the ratemaking procedures adopted by the Commission in this proceeding satisfy the requirements of coordination with PURPA. The final effects of the adopted rate design are shown on Table 6.

Rate Comparison with Oregon - In the continued series of hearings held in May 1980 an exhibit was introduced by Edward L. Ackerman, a witness appearing on behalf of Chapter 788 of the American Association of Retired Persons. Ackerman stated that it appeared to his group that a bias, which may be inadvertent, exists that negatively affects the lifeline allowances of northern California customers. He believes this bias can be shown by comparing the Oregon and California residential rates for homes with electric space and water heat. Ackerman's Exhibit 40 (reproduced herein as Appendix I is Ackerman's exhibit as updated by Pacific (Exhibit 51) to May 1, 1980 rates) did indeed show that the rates in effect in California and Oregon on May 1, 1980 for homes with no electric water or space heat were quite different. California rates exceeded Oregon's by percentages ranging from a low of about 13 to a high of about 35; for the same date a comparison for homes with electric water heat but without electric space heat showed California exceeding Oregon rates by a range of 9 to 32 percent

TABLE 6

Pacific Power & Light Company

Estimated 1979 Sales and Revenues

	Sales M kWh	Present[1] Rates Revenue	Avg. ¢/kWh	Authorized[2] Rates Revenue	Avg. ¢/kWh	Increase Revenue	Increase ¢/kWh	Increase %
Residential								
Lifeline (LL)	164,639	$ 4,021	2.44	4,405	2.68	384	0.24	9.6
Nonlifeline (NLL)	167,990	4,351	2.59	6,792	4.04	2,441	1.45	56.1
Subtotal Res.	332,629	8,372	2.52	11,197	3.37	2,825	0.85	33.7
Nonresidential	323,898	8,436	2.60	11,262	3.48	2,826	0.88	33.5
USBR	15,116	135	0.89	180	1.19	45	0.30	33.6
Subtotal	671,643	16,943	2.52	22,639	3.37	5,696	0.85	33.6
Increased Reconnect Chgs.		-		3		3		
Subtotal		16,943		22,642		5,699		33.6
Other Revenue		2,156		2,099		- 57		
Total Revenue		19,099		24,741		5,642		29.5

Ratios	Present Avg. ¢/kWh	Authorized Avg. ¢/kWh
NLL/LL	1.06	1.51
Sys/LL	1.03	1.26
Sys/Res.	1.00	1.00

1/ Rates in effect before interim Decision No. 91326. Appendix A, Decision No. 91326.

2/ Authorized rates in this decision.

except for 1,000 kWhs during the winter months; and when residential rates were compared for homes with electric space and water heat California was below Oregon in four categories of usage from 1,000 to 4,000 by about 1 to 33 percent, but in all other classes of usage, California rates exceeded Oregon's by a range of about 4 to 32 percent. Ackerman testified that he had tried many ways to get an explanation as to why there is such a difference between California and Oregon bills. No party to this record had an explanation of why there should be a difference in the bills, although the question was asked of several witnesses. Ackerman also urged that the Commission should consider ordering Pacific to include in its billing procedures more definitive information on how lifeline is calculated and what lifeline quantities are available to customers. As discussed elsewhere in this decision, Pacific has instituted a new billing format which shows the lifeline amounts available and the lifeline amounts used on each customer's bill.

Del Norte County Lifeline

One of the reasons for further hearings in this matter involved the lifeline quantities and allowances in Del Norte County, particularly as such allowances affect Crescent City customers. In the interim opinion in this application, Decision No. 91326 dated February 13, 1980, we stated the following:

> "On the appropriateness of lifeline quantities for Del Norte County, the record shows that Del Norte County is a unique climatic area. The summer months in Del Norte County, and in particular the Crescent City area, have temperature ranges which equal those of the winter months in some of the lower coastal California areas. We have addressed and will further consider appropriate lifeline quantities in generic proceedings and will not consider such separately in this proceeding. However, we are interested in taking evidence on how

lifeline allowances in Del Norte County could be administered so as to accomplish more even billings over typical annual periods."

Del Norte County is in climatic Zone 3 for the determination of lifeline quantities. Zone 3 comprises areas with heating degree days in excess of 4,500 but not more than 7,000.[5/] The space heating kWh per month allowance for that zone is 1,120 for each of the six months in the winter season for a total annual space heating lifeline allowance of 6,720 kWh.[6/]

The primary question we face on this issue is whether the annual allotment for Del Norte County should be spread over a greater number of months than six. The only evidence presented on the question was sponsored by staff witness Jhala. Jhala's Exhibit 39 contained a graph reproduced herein as Chart C which provides a graphic representation of the average monthly heating degree days for several California cities. The graph shows that Yreka and Crescent City have identical lifeline heating allowances; however, their climate conditions are quite different. Yreka's curve indicates

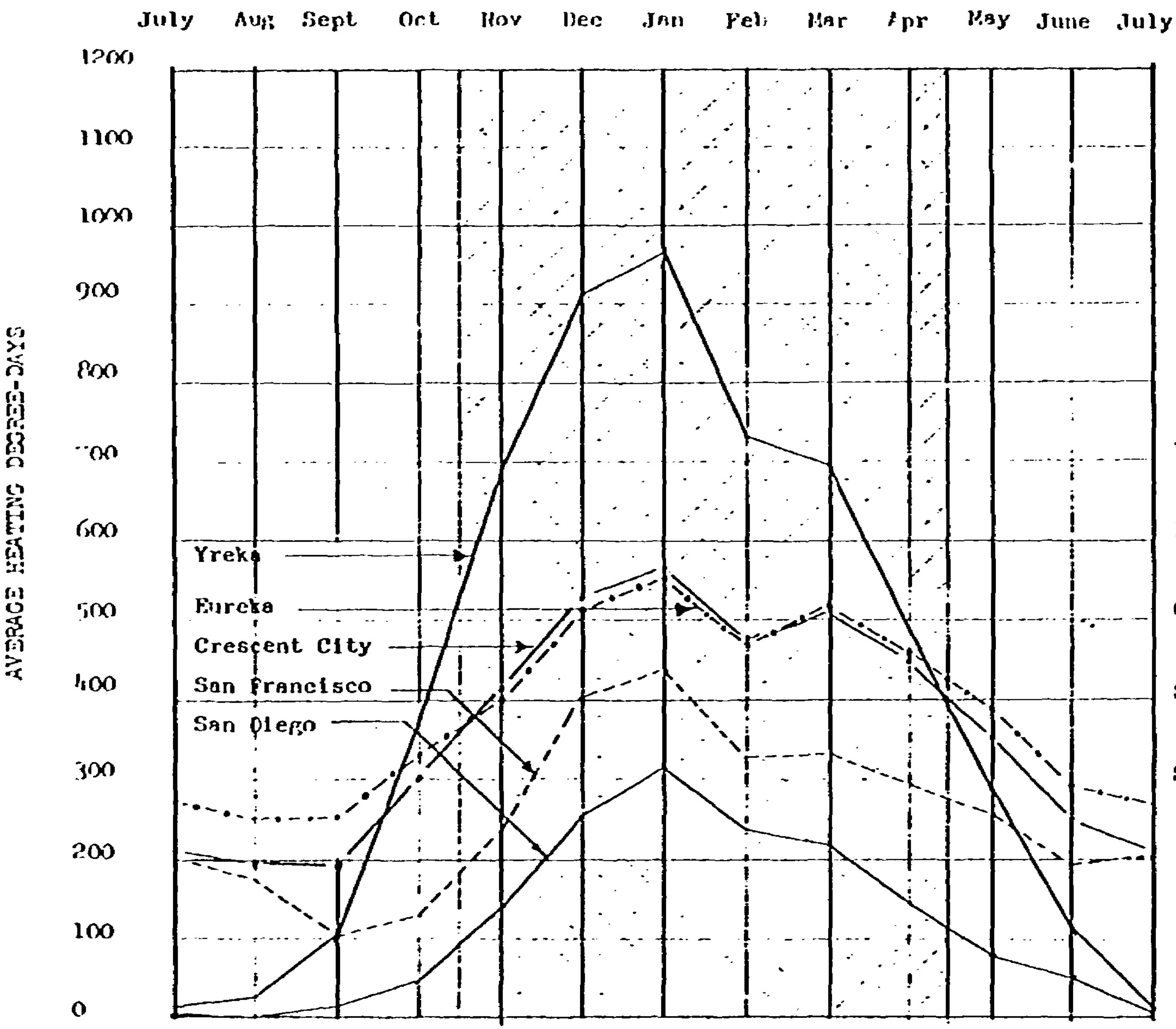
---

5/ Heating or cooling degree days are calculated by relating the average monthly normal temperature, which is derived by averaging the maximum and minimum daily temperatures, to 65° and multiplying that result by the number of days in the month.

6/ It is of interest to note that during its study of the Crescent City data the staff noticed the 30-year average heating degree days for Crescent City was 4,445 rather than the 4,545 as stated in Commission Decision No. 86087 which established the lifeline allowances. Because of this error Crescent City residents are receiving 1,120 kWh per month instead of 800 kWh per month space heating allowance. The staff did not suggest nor recommend that the Crescent City allowance be reduced because the city of Eureka, less than 100 miles south of Crescent City, has 4,679 heating degree days. The staff believes it is appropriate for both cities to have the same amounts because weatherwise they are identical based on staff data compiled for 1971 through 1978.

AVERAGE HEATING DEGREE-DAYS

1941 Through 1970



City	30 Years Average Degree-Days	Space Htg. Allowance kWh/Mo.
Yreka	5,393	1,120
Eureka	4,679	1,120
Crescent City	4,445	1,120
San Fran.	3,080	800
San Diego	1,507	550

CHART C

cold winters and hot summers, whereas Crescent City has a much flatter curve because the summer-winter temperature differences are not as great. One has to conclude that it is the cool spring and summer temperatures that qualify Crescent City for a lifeline allowance equal to that of Yreka. This factor alone may suggest that a longer heating season with smaller monthly kWh allowances would be appropriate for Del Norte County. Witness Jhala agreed that the flatter the line the more appropriate it would be to extend the winter heating season; but the staff makes no recommendation to change the current heating season of the six months, November through April. Unfortunately, the staff did not provide monthly kWh usage data. The only figures considered by the staff were the six-month average usage figures for the summer and winter periods. Therefore, if we are to consider adding one or two months to the heating season, we must make some reasonable estimates of how much energy is actually consumed in the various months. To assume level average usage for each month from November through April for instance, ignores the degree day data shown on Chart C.

In questioning Jhala, the ALJ set up two criteria by which the Commission might want to measure whether a change should be made in the distribution of the lifeline allowance in Del Norte County. These criteria are (1) how the lifeline allowance could be credited to customers in order to give them the minimum total bill for a one-year period, and (2) how a redistribution of the lifeline allowance could accomplish the most even monthly billing over a one-year period. For the first criterion the staff believes the present six-month allowance period would provide the lowest possible yearly bill. In order to accomplish the second, the staff recommends Pacific offer an equal or budget billing plan. Such a plan would take the estimated annual utility bills of a customer and put them on equal monthly payments with any overpayment or underpayment taken care of in the 12th month of the year.

In general, the staff concluded that the space heating period should not be extended because (a) it will encourage increased consumption, (b) put a greater burden on customers with large families and, consequently, large monthly bills, (c) half of the current space heating customers will be required to pay more, and (d) perhaps similar adjustments will be required for most of the coastal areas served by other utilities south of Del Norte County. Pacific agrees with the staff position.

TURN, at first, took no position on this issue; however, based on cross-examination of the staff, it urged through its closing brief that an extension of the winter heating season to eight months coupled with a budget billing plan would best serve the needs of Del Norte County residents. TURN concludes that with the elimination of residential declining blocks by the Commission in this proceeding, virtually no customers will be worse off and very many will be better off under an eight-month heating season. TURN acknowledges that witness Jhala raised a valid point concerning any revenue loss resulting from greater lifeline utilization which will have to be recovered somewhere, quite possibly from the residential class as a whole. However, TURN points out that this should not be a barrier to extension of the heating season because elimination of declining blocks will have a significant negative impact on space heating customers. If extension of the winter season results in shifting of some revenues away from the space heat customers to other residential users, this would tend to soften the impact on D-3 customers (basic plus space) and D-4 customers (basic plus water plus space). TURN claims another significant benefit of extending the heating allowance to eight months would be in the area of conservation; if the winter season is lengthened, thereby lowering the monthly lifeline allowance, more customers will exceed their lifeline allowance thus exposing them to the higher tailblock rates of the inverted rate design.

We believe the evidence is convincing that an extension in Del Norte County of the coming winter season by two months, so that it extends from October through May, will benefit the majority of Pacific's customers in Del Norte County. Also, we believe the best solution to the uneven billing problem is to establish an optional budget billing system by which customers would pay an amount each month equal to one-twelfth of their estimated annual bill. At the end of the year any debit or credit balance would be taken care of in the final month's billing. We also agree with TURN that in order to retain the incentive for conservation under such a system, the monthly bill should contain some type of report indicating whether the customer's usage is above or below the budgeted amount.

We will order a change in duration of the winter heating period over which the present annual lifeline allowance for space heating is allocated. We will also order Pacific to propose a budget billing system to be filed in the form of an advice letter making available budget billing for all of Pacific's customers in California should they desire it. In the near future, we expect to consider the subject of lifeline allowances on a statewide generic basis. Upon completion of the statewide studies, we should be able to set allowances that, while recognizing the widely varying climatic conditions found in California, will be applicable for all utilities.

Lifeline Eligibility and Status

In the morning session of the public meeting held in Crescent City on August 18, 1979, a large number of customers indicated that they were generally unaware of the various lifeline allowances in Pacific's tariffs. Consequently, an explanation of the lifeline allowances was given by both the staff and Pacific personnel. It was recommended that during the noon recess customers check their bills in order to determine their residential rate schedule, and during the afternoon session lifeline eligibility cards were made available so that customers could inform Pacific of their proper lifeline category. As of August 22, 1979 no customers had informed Pacific that they should be receiving a different lifeline allowance than the one they were receiving. Customers who did contact Pacific found that they were receiving correct lifeline allowances. In Pacific's judgment all of the residential customers have been properly notified of the lifeline program and virtually all customers are being billed on lifeline rate schedules which are not less favorable than the ones to which the customers are entitled. Two questions remain. On how and when Pacific should notify its customers that they may be entitled to special lifeline rates, Pacific agreed to do the following: (1) Within 60 days of the Crescent City hearings in 1979, Pacific would send an additional lifeline notification to all persons who had not responded to earlier lifeline mailings; (2) Pacific would follow the PURPA requirements that Pacific inform all of its residential customers of the various rate schedules not less than once each year; and (3) as a result of a staff recommendation, Pacific would modify its bill format and would print all of the residential lifeline rate schedules on each customer's bill. The bill format would notify each residential customer, each month, of the available lifeline rate schedules as well as inform customers of the necessary qualifications for each of the various allowances. The second question concerned how Pacific should inform customers of their status concerning lifeline rates. Pacific responded that it would enclose a postcard with the mailed notice indicated under number (1) above that the customers can return.

All parties agreed with these actions. No further Commission action is required.

Refunds Due to Lifeline Mischarging

The question on this issue is whether there should be refunds ordered for customers who were not properly notified of their eligibility for lifeline rates and, therefore, did not receive such rates because they did not inform Pacific of their proper status.

Pacific claims that there is no evidence on this record that any customer of Pacific failed to receive proper notice of lifeline status. A witness for Pacific outlined its extensive notification efforts, efforts which produced a 95 percent customer response. The assumption is that most of the customers who still have not responded do not have electric water or space heating. All new customers requesting service of Pacific are, as a matter of standard procedure, asked questions by Pacific's personnel concerning their appropriate lifeline allowance even if they are moving into an existing residence.

Also, the staff knew of no customer who failed to receive notice. Staff recommended that any refunds should be granted retroactively to February 1978, a date 30 days after Pacific's last general lifeline mailing. Pacific does not favor such refunds but if they are ordered, then it would request that a balancing account be authorized for recovery in the next rate proceeding. TURN believes that such refunds should be ordered all the way back to April 1977 when lifeline rates first became effective. TURN's position is that if customers have been charged more than what they should have been under the effective tariff, refunds should be mandatory.

There is no evidence that Pacific has failed to provide proper customer notice of the availability of lifeline allowances. Upon this record we cannot order Pacific to provide refunds to customers who hereafter come forward to establish their past eligibility for increased lifeline allowances, unless they can prove that PP&L failed to provide them with the proper notice. We do, however, expect Pacific to make all appropriate adjustments in such customers' rates on a prospective basis. We will, of course, expect Pacific to continue to provide periodic notice as to available rate schedules, in accordance with the requirements of PURPA.

<u>Residential Well Pumping</u>

Another question which arose during the proceedings was what rate consideration should be given for residential well pumping. The staff found that the annual energy requirements to pump the lifeline quantity of water would be approximately four to six kWhs per month. Because of the very small magnitude of the requirements staff believes there is no significant need for a special lifeline allowance and no change should be made to the present lifeline allowances of electrical energy to provide for residential well pumping. Pacific agrees with the staff and no other parties object to the staff's position which we adopt.

Master and Submetering

A question was brought up concerning what provision should be made with respect to metering/submetering for trailer parks and similar establishments. In order to give such master meter customers a discount in accordance with cost, the staff proposes that Pacific's present 10 percent discount be retained and in addition, Pacific assess master meter customers only one customer charge. Pacific concurs with the staff recommendations. No other parties had comments. We will adopt the staff recommendation.

The staff made three other recommendations on multi-family residential service which we will adopt. One, Pacific has not, but should, comply with requirements of Decision No. 88651.[7/] Second, as part of its plan to encourage individual metering,

7/ Ordering Paragraph 5 in Decision No. 88651 dated April 4, 1978 in Case No. 9988, stated:

> "All respondent electric and gas utilities shall immediately initiate an extensive program or expand upon existing programs to encourage the separate metering of units in existing multi-unit residential facilities now served only through a master meter. Each respondent shall file within ninety days after the effective date of this order a comprehensive outline of their program. Thereafter, each respondent shall file semi-annually a report covering progress achieved and further actions proposed."

Pacific should make a survey of all multi-family customers to determine if they are on the appropriate schedule. Third, customers should be informed of the options available, either by mail, personal contact, or as part of an energy conservation audit and survey.

Impact of Increases
On Schools and Hospitals

Pacific has approximately 60 schools and hospitals in its California service territory and they are served on either General Service Schedule A-32 or Large General Service Category Schedule A-36. The effect of Pacific's rate proposals on schools and hospitals served on Schedule A-32 is an increase of approximately 34 percent. If the Commission should grant Pacific's request for those schools and hospitals served on Schedule A-36, the increase would be approximately 32 percent. Pacific's rate proposals are based on keeping the residential lifeline adjustment within the residential class. It appears from the rate schedules that we will adopt in this proceeding that the impact of the increases on schools and hospitals will generally be the same as on residential customers which we believe to be a fair treatment.

Conservation Programs

Staff engineer Brian D. Schumacher testified concerning Pacific's conservation programs. He concluded that Pacific's program as a whole is far better than the nationwide effort and equal to or better than that of many California utilities. He added that the President of the Commission has held Pacific's conservation program up as being something that other utilities might emulate.

The staff concluded the following in its report on Pacific's conservation programs:

- All conservation programs appear to be cost-effective.

- Programs, which after trial have not proved to be cost-effective, have been discontinued.
- Pacific has submitted no goals for conservation effectiveness, and for 1979 is claiming only one-eighth to one-third of the annual amount necessary to meet state and national goals.
- Pacific has been involved in both cogeneration and solar domestic water heating for some years but no actual energy conservation as a result of Pacific's activities in these areas is either claimed or apparent.

Witness Schumacher makes the following 15 recommendations which are concurred in by Pacific for purposes of this proceeding:

1. Pacific should be directed to implement and expand its conservation programs planned for 1979 and succeeding years.
2. Pacific should be granted $195,000 annually in rates as requested to support its conservation programs and other customer service and informational expenses.
3. Pacific should be granted an additional $15,000 now budgeted for incentives as authorized in Decision No. 90308.
4. Pacific should be directed to report its expenses for CVR as a separate item when next applying to this Commission for rate relief.
5. Pacific should increase its number of energy consultants for both home and commercial/industrial energy analyses.
6. Pacific should identify which advertising programs are most successful in generating requests for energy analyses and emphasize those in order to fully utilize the trained energy consultants.
7. Pacific should submit with its regular March 31, 1980 report, sales estimates by customer class based on all factors <u>except</u> conservation by utility, customer, <u>and</u> government mandate for the five years 1979 through 1983.

8. Pacific should submit in connection with sales estimates, and support within the submittal, its estimate of conservation total potential, the conservation utility goal, and the conservation forecasted amount or percentage, for each class (or conservation program, covering all classes) by year, through 1983.

9. Pacific should explain and support each difference it reports between the conservation forecasted and the annual amount needed to meet the Commission staff's goal of a 20 percent total reduction by 1983 over normalized year 1978 usage.

10. Pacific should develop and implement a cost-effective agricultural and water utility pump testing program.

11. Pacific should submit quarterly interim reports on the results of its CVR circuit test, including an analysis of the mix of load types on the circuit.

12. Pacific should submit formal plans and schedules for reaching circuit-by-circuit conclusions about the cost-effectiveness of CVR and for implementation of Phase II Projects where cost-effectiveness is indicated.

13. Pacific should submit a June 1979 progress report on its solar water heating test program.

14. Pacific should submit a plan and schedule for cost-effective conversion from mercury vapor to high pressure sodium streetlights.

15. Pacific should further revise its bills to provide its customers with additional information about the effectiveness of their individual conservation efforts. The bill should include:

    a. Customer's usage for the current month and corresponding month of the prior year,

b. Customer's average usage per day for the current month and corresponding month of the prior year,

c. Customer charge,

d. Lifeline quantity and rate, and commodity charge in dollars,

e. Nonlifeline quantity and rate, and commodity charge in dollars, and

f. Energy conservation messages.

A sample of a modified bill format incorporating this information for another California electric utility, Southern California Edison Company, is included as Appendix J.

Conservation Voltage Regulation (CVR)

Staff witness Schumacher testified that Pacific's delay in studies and implementation of CVR may have cost its California ratepayers as much as $54,000. This amount is 0.06 percent of the staff's estimated rate base of $86,480,000. The staff claims it could make a similar estimate based on the lack of an irrigation pump test program if it could have obtained the necessary data. Based on those observations, the staff points out it could recommend shifting some of the financial burden from Pacific's customers to its stockholders through a reduction in rate of return. However, recently the staff was informed that Pacific's average distribution voltage has been less than the maximum allowable, as noted earlier. In addition, a staff in-depth study of methodology for adjustments to rate of return for conservation considerations, upon which any recommendation should be based, is not yet complete. Overall, considering the projected effectiveness of the conservation program Pacific now has in place and its experience through trial and error which lends confidence to these estimates, staff makes no recommendation that rate of return be adjusted for conservation effectiveness.

TURN recommends the Commission adopt the staff estimate of $54,000 and adjust the final adopted rate of return accordingly.

Because of Pacific's concurrence in the staff recommendations regarding conservation, and Pacific's recent cooperative effort in a weatherization program (Decision No. 91497, supra) we will adopt the staff's recommendation.

TURN Request for PURPA Funds

TURN has petitioned in this proceeding for participation funds pursuant to Section 122 of PURPA. In Decision No. 91909, dated June 17, 1980, we adopted rules for such requests for funding. Petitions for rehearing of that decision are still pending before this Commission, and may at some future point be the subject of petitions for writ of review before the California Supreme Court. We will therefore defer a decision on TURN's petition until our own review of the petitions for rehearing, and, if necessary, that of the Court, are completed.

Optional Notice of Intent (NOI) Procedure

We recognize that this proceeding has taken an unusually long time to conclude. This is partly due to the further hearings required and partly to the time needed by our staff to develop the data necessary for the revised allocation procedure. As we stated in the interim decision, under our Regulatory Lag Plan for major utilities in California our intent is to conclude rate cases within one year and Pacific should not be treated differently. Accordingly, we invite Pacific at its option to use the NOI procedure as adopted by Resolution No. M-4706 for its next rate case.

Findings of Fact

1. By this application Pacific requests increases in its electric service revenues for its California customers in the amount of $6,287,000 or 37.1 percent over revenues under present rates based on the test year 1979.

2. Duly noticed hearings in this application were held in 1979 and were continued in May 1980, at which all interested parties had an opportunity to be heard.

3. By Decision No. 91326 dated February 13, 1980 Pacific was authorized a partial general rate increase to produce additional revenues of $4,276,000 or 25.2 percent over revenues under rates in effect prior to February 13, 1980 based on the test year 1979.

4. The relationship of California kWh sales as a percent of system has been declining steadily although the rate of decline is decreasing.

5. The average California kWh usage per customer is greater than the system average.

6. The difference of kWh usage in California versus the system stabilized in 1972 at approximately 1,000 kWhs per customer per year.

7. Over the last ten years the Pacific system outside California has been growing much more rapidly than the California portion of the system.

8. When the Commission approved the COPCO/Pacific merger in 1961 it did not stipulate that any particular allocation procedure should be used for determining the California results of operations under the merged system.

9. Allocation procedures should be changed when appropriate to reflect the changing conditions of utility systems and subsystems.

10. Adoption of a growth share method of cost allocation throughout Pacific's service area would provide more accurate price signals and more effective conservation incentives to customers than does the present integrated system method.

11. A growth share method, like other allocation methods, uses units to determine the allocations of plant and expenses, such units merely reflecting the jurisdictional rate year relationships for a given rate case.

12. and 13. - not used.

14. Unilateral adoption of a growth share method would invite other states with jurisdiction over Pacific to likewise improvise inconsistent cost allocation methods and would create a risk of federal preemption.

15. An incremental approach to growth share would allocate to California an appropriate share of the cost of growth, and adoption of such an allocation method should be pursued through cooperation with other state regulatory authorities.

16. This Commission's obligation to California ratepayers has been discharged if the rates paid by consumers are based on results of operations which reimburse Pacific for the expenses and return necessary to maintain an operation sufficient to serve California.

17. The California results of operations adopted in this decision based on the integrated system allocation method reflect those costs which Pacific incurs in serving California customers and allows Pacific the opportunity to earn a reasonable return on the plant allocated to California for support of the California system.

18. Peak demand data used in the future for allocation purposes should be based on a 12-month average coincidental peak demand.

19. In future proceedings if temperature data are used for adjusting historical data, that data should be the most recent available.

20. Allocations made for future proceedings should employ data from appropriately consistent periods.

21. There is no evidence in the record of the estimated results of California operations that the state facilities allocation procedure would produce.

22. For purposes of an integrated system allocation, the allocation made by Pacific, as adjusted by the staff, is appropriate.

23. The basic system rate base estimated by Pacific, as adjusted by the staff, is reasonable for the purposes of the results of operations in this proceeding.

24. The estimated basic system expenses for the rate year 1979, as presented by Pacific and adjusted by the staff, are reasonable for purposes of this proceeding.

25. Pacific has properly accounted for the refunds in California required by Proposition 13 property tax reductions.

26. If a utility accomplishes a reduction in an anticipated expense that was found reasonable by the Commission for the purpose of setting rates in a previous case, the Commission should not order a refund unless such a reduction was anticipated.

27. The staff approach to adjusting California allocated expenses as a result of property tax refunds to Pacific in the State of Oregon is appropriate and should be adopted.

28. A reduction in California fuel expense of $25,600 is appropriate to account for the fact that Pacific controls the Bridger Coal Company from which it buys coal for its operations.

29. For purposes of this proceeding the staff rate of return recommendation, adjusted for an appropriate update of information the staff relied upon for its estimate, is reasonable.

30. An overall rate of return of 10.09 percent, the detail of which is shown in this decision, is reasonable.

31. Staff recommendations concerning future treatment of revenues, expenses, and rate base as outlined in this opinion are reasonable and should be adopted.

32. Pacific's conservation program as a whole is far better than the nationwide effort and equal to or better than that of many California utilities.

33. The staff recommendations concerning further efforts by Pacific toward conservation are reasonable and should be adopted.

34. Pacific has delayed studies and implementation of CVR which may have cost California ratepayers as much as $54,000.

35. Because of Pacific's concurrence in the staff recommendations regarding further conservation efforts and Pacific's recent cooperative effort in a weatherization program, as approved by Decision No. 91497, the staff's recommendation that Pacific should not be penalized through a reduction in rate of return for the cost to California ratepayers of delay in implementation of CVR is reasonable and should be adopted.

36. In Pacific's next rate case before this Commission all parties participating should make recommendations on how to pass through to California ratepayers the real savings of the California weatherization program approved by Decision No. 91497.

37. It is the duty of this Commission to encourage conservation.

38. Rewarding customers for their conservation efforts relative to the conservation efforts of other states is a valid goal.

39. It is a legitimate Commission action to reward consumers who try to conserve by giving them lower rates.

40. The procedures by Pacific concerning (a) lifeline eligibility notification, (b) modification of Pacific's bill format so that residential lifeline rate schedules are on each customer's bill, (c) distribution of information to customers of the necessary qualifications for the various lifeline allowances, and (d) notification to customers of their lifeline rate status are satisfactory.

41. All of Pacific's residential customers have been properly notified of the lifeline program and virtually all customers are being billed on lifeline rate schedules which are not less favorable than the ones to which the customers are entitled.

42. Pacific has proper tariff provisions in effect to provide additional payments to Pacific or refunds by Pacific in case of mischarging.

43. In order to achieve the minimum total bill for a one-year period through the maximum usage of the lifeline allowance, the upcoming winter period for lifeline usage in Del Norte County should be extended from the present six-month period of November through April to an eight-month period of October 1980 through May 1981, with the present annual lifeline space heating allowance of 6,720 kWh spread equally over that period.

44. There is no significant need for a special lifeline allowance for residential well pumping.

45. Pacific should comply with the reports required by Decision No. 88651 concerning programs to encourage the separate metering of units in existing multi-unit residential facilities served only through a master meter.

46. As part of its plan to encourage individual metering, Pacific should make a survey of all multi-family customers to determine if they are on the appropriate schedule.

47. Pacific's customers residing in multi-unit residential facilities should be informed of the options available for metering their service either by mail, personal contact, or as a part of an energy conservation audit and survey.

48. Pacific's proposals to change the PA-20 agricultural tariff are reasonable except that Pacific should be required to file an advice letter prior to the 1981 season establishing procedures whereby customers on the tariff may, at their option, read their meters through a postcard procedure as described in this decision.

49. The staff recommendations on tariff revisions and records to be kept for customer-owned and company-owned street lights should be adopted.

50. The staff recommendation concerning Pacific's provision to consumers of graphs of monthly rates versus lumen size for street lights is reasonable and should be adopted.

51. In order to achieve a more uniform monthly billing over a one-year period, Pacific should offer its customers the option of a budget billing system.

52. The rates and rate designs in the appendices to this decision, and which will produce estimated additional annual revenues of $1,366,000 over interim rates now in effect, are reasonable and should be adopted.

53. The rate increases authorized by this decision and Interim Decision No. 91326, supra, comply with the voluntary wage/price guidelines as issued by the Federal Council on Wage and Price Stability.

54. The ratemaking procedures adopted in this proceeding satisfy the requirements of coordination with PURPA.

55. The rate schedules adopted herein will result in increases for schools and hospitals of generally the same magnitude as for the average residential customer and is a fair treatment.

56. 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.

57. There is an immediate need for the rate relief authorized herein because Pacific is already incurring the costs which will be offset by the rate increase authorized because 1979, the rate year for which the increase has been calculated, is now past.

Conclusions of Law

1. Pacific should be authorized to place into effect the increased rates found to be reasonable in the findings set forth above.

2. The effective date of this order should be the date hereof because there is an immediate need for rate relief.

SECOND 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 Appendices A-G to this decision and concurrently withdraw and cancel its presently effective schedules. Such filing shall comply with General Order No. 96-A.

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

3. Until further order of the Commission, Pacific shall adjust its billing system and tariffs so that the present annual lifeline space heating allowance for Del Norte County is spread equally over the period October through May instead of November through April.

4. Pacific shall file an advice letter prior to the 1981 irrigation season which establishes procedures whereby customers using the PA-20 tariff may, at their option, read their meters through the postcard procedure described in this decision.

5. Within sixty days from the effective date of this decision Pacific shall comply with the reporting requirements of Decision No. 88651.

6. Concerning multi-unit residential facilities metering, Pacific shall:

   a. Make a survey of all multi-family customers to determine if they are on the appropriate schedule and

   b. Inform customers of the options available for metering their service.

7. Within sixty days from the effective date of this decision Pacific shall file an advice letter establishing the optional budget billing system described in this decision; the system shall be subject to Commission review and approval by resolution.

8. As part of its next general rate application, Pacific shall provide a proposal for allocation of costs to its California service area based upon a growth share method as discussed herein.

9. TURN's petition for participation funds under Section 122 of PURPA will remain open until our review of petitions for rehearing, and, if necessary, that of the California Supreme Court, on Decision No. 91909 is completed.

The effective date of this order is the date hereof.

Dated NOV 18 1980, at San Francisco, California.

John E. Bryson
President
Vernon L. Sturgeon
Richard D. Gravelle
Claire T. Dedrick
Leonard M. Grimes, Jr.
Commissioners

APPENDIX A

RESIDENTIAL SERVICE

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.

RATES

	Per Meter Per Month	
Basic Charge:	$2.00	
Energy Charge:	Per Month	
	Lifeline Rates	Non-Lifeline Rates
All kWh per kWh	2.337¢	4.042¢

Minimum Charge:

The monthly minimum charge shall be the Basic Charge. 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 family dwellings such as apartments, complexes, condominiums and mobile home parks in which the single-family dwellings receive service directly from the Utility through separate meters.

GENERAL SERVICE

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: (a) intermittent or highly fluctuating loads, or (b) seasonal use. 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.

RATES

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:

4.485¢ per kWh for the first 6,000 kWh plus 75 kWh per kWh for each kW of Billing Demand in excess of 20 kW.
2.655¢ per kWh for all additional kWh.

GENERAL SERVICE

Schedule No. A-32

GENERAL SERVICE
(Continued)

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

Reactive Power Charge:
The maximum 15-minute integrated reactive demand in kilovolt-amperes occurring during the month in excess of 60% of the maximum measured 15-minute integrated demand in kilowatts occurring during the month will be billed, in addition to the above charges, at 45¢ per kVa of such excess reactive demand.

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

TERM OF CONTRACT
Not less than five years for seasonal service and not less than one year for all other service.

SPECIAL CONDITIONS
1. Temporary disconnection of any portion of load will not be considered as affecting the monthly minimum charge.
2. For recurrent seasonal or intermittent service to a permanently established business or enterprise, the total annual billing shall be not less than twelve times the monthly minimum charge.
3. For commercial buildings, apartment houses, court groups, auto camps, and the like, for which individual customers are submetered, the charge to individual customers must be at the Utility's regular tariff rate for the type of service which such individual customer may actually receive.

GENERAL SERVICE

Schedule No. A-33

GENERAL SERVICE
PARTIAL REQUIREMENTS SERVICE

APPLICABILITY

Applicable to partial requirements, supplementary, or standby electric service furnished for loads having other energy sources, including on-site generation, at a single point of delivery at Utility's locally standard voltage. Not applicable to service for: loads which have registered 500 kw or more, more than once in any consecutive 18-month period, resale, intermittent or highly fluctuating loads, or seasonal use. This schedule is not required where on-site generation is employed only for emergency supply during utility outage.

TERRITORY

Within the entire territory served in California by the Utility.

MONTHLY BILLING

The monthly billing shall be the sum of the Electric Service Charge, the Standby Charge and the Reactive Power Charges.

Electric Service Charge:

The Electric Service Charge shall be computed in accordance with the Basic, Demand, Energy, Minimum, and Voltage Charges of Schedule A-36 of this tariff; provided, however, that the Billing Demand shall be as defined herein.

Standby Charge:

$1.25 per kW shall be applied to 50% of the kW by which customer's Contract Capacity or Total Load Demand, as provided by contract, exceeds the Billing Demand.

The service contract shall specify customer's selection from stated alternatives of service provisions by which the magnitude of Utility's service and of the kW applicable to the standby charge is determined from (a) customer's Total Load Demand, including any coincident power supplied by customer's on-site generation, or, alternatively, by (b) a Contract Capacity expressed as a fixed total number of kW.

In the absence of a currently applicable service contract for qualifying service from preexisting facilities, the $1.25 per kW shall be applied to 80% of the number by which the Billing Demand in kW is exceeded by the rated kVa capacity of the service transformer or, where service is furnished directly from Utility's primary-voltage distribution system serving other customers, by the maximum kW of the record of service for the most recent three years.

GENERAL SERVICE

Schedule No. A-33

GENERAL SERVICE
PARTIAL REQUIREMENTS SERVICE
(Continued)

Reactive Power Charges:
The maximum 15-minute integrated reactive demand in kilovolt-amperes occurring during the month in excess of 60% of the maximum measured 15-minute integrated demand in kilowatts occurring during the month will be billed at 45¢ per kVa of such reactive demand. In addition, all reactive kilovolt-ampere hours (kVarh) which are registered in excess of 60% of the registered monthly kilowatt-hours (kWh) will be billed at 0.06¢ per kVarh.

BILLING DEMAND
The Billing Demand shall be the greater of the following:

(a) the measured kW shown by or computed from the readings of Utility's demand meter for the 15-minute period of greatest deliveries to customer during the billing month, determined to the nearest kW.

(b) the average of the three greatest monthly measured kw demands established during the 12-month period which includes and ends with the current billing month, or

(c) 100 kW.

TOTAL LOAD DEMAND (where specified in Contract)
The measured kW shown by or computed from Utility's demand totalizer meter of the 15-minute period of greatest coincident total of customer's power use from customer's generation and from power supplied by Utility. Said demand kW as used for billing shall not exceed the kVa setting of any protective devices which limit the power available to customer from Utility.

TERM OF CONTRACT
By written service contract for not less than five years.

RULES AND REGULATIONS
Service hereunder is subject to the General Rules and Regulations contained in the Utility's regularly filed and published tariff and to those prescribed by regulatory authorities having jursidiction hereof.

LARGE GENERAL SERVICE

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: (a) intermittent or highly fluctuating loads, or (b) seasonal use. 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.

RATES

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:

1.942¢ 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.

LARGE GENERAL SERVICE

Schedule No. A-36

LARGE GENERAL SERVICE - Optional
(Continued)

Reactive Power Charge:

The maximum 15-minute integrated reactive demand in kilovolt-amperes occurring during the month in excess of 60% of the maximum measured 15-minute integrated demand in kilowatts occurring during the month will be billed, in addition to the above charges, at 45¢ 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.

For as long as Company elects for its operating convenience to meter electric service to customer at primary voltage, the above charges shall be reduced by one and one-half percent (1 1/2%) to compensate for losses.

For as long as delivery to customer is made at the current locally standard primary voltage (11 kV or greater), the above charges for any month will be reduced by 15¢ per kW of load size used for the determination of the monthly Basic Charge; and where such deliveries are metered at primary voltage, a $35 per month high voltage charge will be added.

Company retains the right to change its line voltage or classifications thereof at any time, and after reasonable advance notice to any customer affected by such change, such customer then has the option to take service at the new line voltage or to accept service through transformers to be supplied by Company. Customer must accept delivery at the new line voltage to qualify for the above stated billing reductions.

The reduction of charges shall not operate to reduce minimum charges for the first 100 kW.

BILLING DEMAND

The billing demand shall be the greater of the following:

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

TERM OF CONTRACT

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

SPECIAL CONDITIONS

1. Temporary disconnection of any portion of load will not be considered as affecting the monthly minimum charge.

TIME OF USE

Schedule No. AT-47

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

APPLICABILITY

Applicable to partial requirements, supplementary, or standby electric service furnished for contract capacities of 500 kW and over or for takings which have ever registered 500 kW or more, more than once in any consecutive 18-month period, having other energy sources, including on-site generation, at a single point of delivery at Company's locally standard voltage. This schedule will remain applicable until customer fails to equal or exceed 500 kW for a period of 36 consecutive months. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Not applicable to service for: resale, intermittent or highly fluctuating loads or seasonal use. This schedule is not required where on-site generation is employed only for emergency supply during utility outage.

TERRITORY

Within the entire territory served in California by the Utility.

MONTHLY BILLING

The monthly billing shall be the sum of the Electric Service Charge, the Standby Charge, and the Reactive Power Charges.

Electric Service Charge:

The Electric Service Charge shall be computed in accordance with the Basic, Demand, Energy, Minimum, and Voltage Charges of Schedule AT-48 of this tariff; provided, however, that the Billing Demand shall be as defined herein.

Standby Charge:

$1.25 per kW shall be applied to 50% of the kW by which customer's Contract Capacity or Total Load Demand, as provided by contract, exceeds the Billing Demand.

This service contract shall specify customers' selection from stated alternatives of service provisions by which the magnitude of Utility's service and of the kW applicable to the standby charge is determined from (a) customer's Total Load Demand including any coincident power supplied by customer's on-site generation or, alternatively, by (b) a Contract Capacity expressed as a fixed total number of kW.

In the absence of a currently applicable service contract for qualifying service from preexisting facilities the $1.25 per kW shall be applied to 80% of the number by which the Billing Demand in kW is exceeded by the rated kVa capacity of the service transformer or, where service is furnished directly from Utility's primary-voltage

TIME OF USE

Schedule No. AT-47

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

MONTHLY BILLING (Continued)

Standby Charge: (Continued)
distribution system serving other customers, by the maximum kW of the record of service for the most recent three years.

Reactive Power Charges:
The maximum 15-minute integrated reactive demand in kilovolt-amperes occurring during the month in excess of 60% of the maximum measured 15-minute integrated demand in kilowatts occurring during the month will be billed at 45¢ per kVa of such reactive demand. In addition, all reactive kilovolt-ampere hours (kVarh) which are registered in excess of 60% of the registered monthly kilowatt-hours (kWh) will be billed at 0.06¢ per kVarh.

BILLING DEMAND
The Billing Demand shall be the greater of the following:

(a) the measured kW shown by or computed from the readings of Utility's demand meter for the 15-minute period of greatest deliveries to customer during the billing month, determined to the nearest kW.

(b) the average of the three greatest monthly measured demands, including On-Peak Period demands and any Off-Peak Period demands which exceed the Contract Capacity, established during the respective Summer or Winter months of the 12-month period which includes and ends with the current billing month, or

(c) 500 kW.

TOTAL LOAD DEMAND (where specified in Contract)
The measured kW shown by or computed from Utility's demand totalizer meter of the 15-minute period of greatest coincident total of customer's power use from customer's generation and from power supplied by Utility. Said demand kW as used for billing shall not exceed the kVa setting of any protective devices which limit the power available to customer from Company.

TERM OF CONTRACT
By written service contract for not less than five years.

RULES AND REGULATIONS
Service hereunder is subject to the General Rules and Regulations contained in the Utility's regularly filed and published tariff and to those prescribed by regulatory authorities having jurisdiction hereof.

TIME OF USE

Schedule No. AT-48

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

APPLICABILITY

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

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

TERRITORY

Within the entire territory served in California by the Utility.

MONTHLY RATES

Basic Charge:

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

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

Demand Charge:

On-Peak Period Demand (Monday through Friday: 6:00 a.m. to 10:00 p.m.)	Winter** Months	Summer** Months
For each kW of Billing Demand	$1.52	$1.00

**Note: Winter charges shall apply to consumption in the six regular monthly billing periods November through April.

Summer charges shall apply to consumption in the six regular monthly billing periods May through October.

TIME OF USE

Schedule No. AT-48

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

Energy Charge:
1.799¢ 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 60% of the maximum measured 15-minute integrated demand in kilowatts occurring during the month will be billed, in addition to the above charges, at 45¢ 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.

For as long as Company elects for its operating convenience to meter electric service to customer at primary voltage, the above charges shall be reduced by one and one-half percent (1 1/2%) to compensate for losses.

For as long as delivery to customer is made at the current locally standard primary voltage (11 kV or greater), the above charges for any month will be reduced by 15¢ per kW of load size used for the determination of the Monthly Basic Charge; and where such deliveries are metered at primary voltage, a $35 per month high voltage charge will be added.

Company retains the right to change its line voltage or classifications thereof at any time, and after reasonable advance notice to any customer affected by such change, such customer then has the option to take service at the new line voltage or to accept service through transformers to be supplied by Company. Customer must accept delivery at the new line voltage to qualify for the above stated billing reductions.

The reductions of charges herein shall not operate to reduce minimum charges for the first 500 kW.

BILLING DEMAND

The Billing Demand shall be the greater of the following:

(a) the maximum measured 15-minute integrated On-Peak Period demand in kilowatts occurring during the month.

TIME OF USE

Schedule No. AT-48

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

(b) 50% of the highest demand established during the respective Summer or Winter months of the 12-month period which include and end with the current billing month, or
(c) 500 kW.

TERM OF CONTRACT

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

SPECIAL CONDITION

Temporary disconnection of any portion of load will not be considered as affecting the monthly minimum charge.

OTHER RATES

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.

RATES

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

Energy Charge:
2.008¢ 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.

OTHER RATES

Schedule No. AWH-31

COMMERCIAL WATER HEATING SERVICE

NO NEW SERVICE
(Continued)

3. Water heaters shall be of the enclosed storage type of not less than 30-gallon capacity. The water heating elements shall be operated in blocks not to exceed 10 kW each or one-third of the total water heating capacity under this schedule, whichever is greater. Such operation shall employ separate thermostats for each such block or shall be otherwise arranged so that not more than one block will be turned on or off within any 10-second interval.

4. The Utility may, by written agreement with the customer, provide volume water heating service on an annual or summer seasonal basis under this schedule. The Utility reserves the right to attach special conditions and minimum charges to such service.

5. All water heaters and their installation must conform to applicable municipal, state and national codes.

6. Service will not be supplied except to customers receiving service hereunder on April 21, 1975 and then only at the locations then occupied. Service will not be rendered hereunder in the event of any increase in customer's connected load after April 21, 1975. Whenever service hereunder is discontinued for any reason, it will not be re-established under this schedule.

OTHER RATES

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.

RATES

Type of Luminaire	Nominal Lamp Rating	Per Luminaire Per Month
Mercury Vapor	* 7,000 lumens	$ 6.53
" "	*21,000 "	11.85
" "	*55,000 "	23.37
High Pressure Sodium	5,800 "	$10.17
" " "	22,000 "	14.14
" " "	50,000 "	21.72

*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.

OTHER RATES

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.

RATES

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

Energy Charge:

4.232¢ 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.

STREET AND HIGHWAY LIGHTING

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	$ 5.87
22,000	9.64
50,000	17.82

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.

STREET AND HIGHWAY LIGHTING

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 3.030¢ 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.

STREET AND HIGHWAY LIGHTING

Schedule No. LS-52

SPECIAL STREET AND HIGHWAY LIGHTING SERVICE

UTILITY-OWNED SYSTEM
(Continued)

SPECIAL CONDITIONS

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

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

3. 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.

STREET AND HIGHWAY LIGHTING

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 3.520¢ per kWhr.

b) Where the customer operates and maintains the system, a flat rate equal to one-twelfth the estimated annual energy cost at 3.520¢ 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.

STREET AND HIGHWAY LIGHTING

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.

STREET AND HIGHWAY LIGHTING

Schedule No. LS-57

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

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	$2.78	$3.11	$4.87	$6.56	$8.33
Mercury-Vapor Lamps					
Nominal Lumen Rating				7000	21000
Rate per Lamp - horizontal				$5.85	$9.99
Rate per Lamp - vertical				5.31	$9.64

Street lights on metal poles:

Mercury-Vapor Lamps		
Nominal Lumen Rating	7000	21000
Rate per Lamp		
Horizontal	$8.06	--
Horizontal	--	$12.73

B. Underground System

Street lights on metal poles:

Mercury-Vapor Lamps		
Nominal Lumen Rating	7000	21000
Rate per Lamp		
Horizontal	--	$16.25
Vertical	--	$14.30

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	$6.58	$10.58	$21.50

STREET AND HIGHWAY LIGHTING

Schedule No. LS-57

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

CONVERSION OF UTILITY-OWNED LIGHTS

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

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

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

SPECIAL CONDITIONS

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

A. 58605 ALJ/BAD/ec

APPENDIX F
Page 8 of 9

STREET AND HIGHWAY LIGHTING

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	$ 1.30	$ 2.52
2,500	2.57	3.84
4,000	4.19	5.51
6,000	5.74	7.11
	MERCURY-VAPOR	
7,000	$ 2.68	$ 3.42
21,000	6.05	6.84
55,000	14.50	15.57
	FLUORESCENT	
21,400	$ 5.74	$ 7.69

STREET AND HIGHWAY LIGHTING

Schedule No. LS-58

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

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.

AGRICULTURAL PUMPING SERVICE

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
Except for November, the monthly billing shall be the sum of the applicable Demand and Energy Charges and the Reactive Power Charge. For November, the billing shall be the sum of the Energy Charge, the Reactive Power Charge, and the Annual Charge.

Meter Readings From March 27 through November 27

Energy Charge:
2.361¢ per kWh for the first 14,000 kWh
1.431¢ per kWh for all additional kWh

Annual Charge:

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

Meter Readings From November 28 through March 26

Demand Charge:
$1.00 per kW of monthly Billing Demand

Energy Charge:
4.111¢ per kWh for the first 100 kWh monthly per kW of monthly Billing Demand
2.301¢ per kWh for all additional kWh

AGRICULTURAL PUMPING SERVICE

Schedule No. PA-20

AGRICULTURAL PUMPING SERVICE
(Continued)

Reactive Power Charge:
The maximum 15-minute integrated reactive demand for the month in kilovolt-amperes occurring during the month in excess of 60% of the maximum measured 15-minute integrated demand in kilowatts occurring during the month will be billed, in addition to the above charges, at 45¢ per kVa of such excess reactive demand.

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 through 3 HP	3 kW
From 3 through 5 HP	5 kW
From 5 through 7.5 HP	7 kW
From 7.5 through 10 HP	9 kW

SPECIAL CONDITIONS

1. Pumping service during the period other than the irrigation season will be furnished at the same delivery point to any irrigation customer served hereunder; provided, however, that the Utility may, at its discretion, require the customer to limit his hours of operation to not more than eighteen hours in any one day. The hours of operation will be designated by the Utility. If operation is for other hours than those designated by the Utility, the entire use will be billed on the applicable general service schedule.

2. 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.

3. Reactive Power Charge: When the connected load is in excess of 50 HP, reactive metering will be installed and charges for reactive power will be as follows:

4. No billing will be rendered until the accumulated measured kWh equal or exceed 50 kWh.

PACIFIC POWER & LIGHT COMPANY
ILLUSTRATION OF APPLICATION OF THE GROWTH SHARE METHOD TO TEST YEAR 1979
ALLOCATION NOTES
1979 Estimated Test Period

			Growth Share Allocation	
			Prior to 1975	1976-79
1.	Electric - California	4.0000%	4.32%	3.539%
	- Oregon	62.7200%		
	- All Other	33.2800%		

Based on the relative contribution of separate state demands to the five-state system peak. These are calculated by trending historical temperature adjusted (except for Montana and Wyoming) demands at the time of system peak over the past five years.

1A.	Electric - California	3.7577%	3.9148%	2.942%
	- Oregon	60.3097%		
	- All Other	35.9326%		

Based on KWh sales in the states of California, Oregon, Washington, Montana, and Wyoming for the 12 months ending September 30, 1978.

2.	Electric - California	6.7795%	6.76%
	- Oregon	59.9756%	
	- All Other	33.2449%	

Transmission plant investment in the Oregon-Washington-California-Montana-Wyoming system is assigned on the basis of use to group "A" or to "local." "Local" plant is directly assigned to the state to which it relates and the group "A" or joint use portion is allocated on the basis of Note 1.

2A.	Electric - California	3.5160%	3.31%
	- Oregon	55.1310%	
	- All Other	41.3530%	

Transmission plant investment in Wyoming is assigned on the basis of use to "local" or "system." The amount of system investment is allocated on basis of Note 1.

2B.	Electric - California	2.5505%	2.37%
	- Oregon	39.9917%	
	- All Other	57.4578%	

Investment in Montana transmission plant is assigned on the basis of use; jointly used plant is allocated on the basis of Note 1.

			Growth Share Allocation
3.	Electric - California	4.8261%	4.96%
	- Oregon	73.7154%	
	- All Other	21.4575%	

Investment in Oregon transmission plant is assigned on the basis of use; jointly used plant is allocated on the basis of Note 1.

4.	Electric - California	2.8768%	3.10%
	- Oregon	45.1080%	
	- All Other	52.0152%	

Investment in Washington transmission plant is assigned on the basis of use; jointly used plant is allocated on the basis of Note 1.

5.	Electric - California	55.0345%	49.75%
	- Oregon	29.6134%	
	- All Other	15.3521%	

Investment in California transmission plant is assigned on the basis of use; jointly used plant is allocated on the basis of Note 1.

6. Electric - Oregon 79.3800%

All Other Utility Operations 20.6200%

Based on Northwestern Electric Company investment in 1947.

7.	Electric - California	16.6428%
	- Oregon	83.3572%

Based on The California Oregon Power Company investment in 1961.

8.	Electric - California	4.3746%
	- Oregon	70.2115%
	- All Other	25.4139%

Calculated the same as Note 1A excluding Washington.

9.	Electric - California	2.0000%
	- Oregon	31.3600%

All Other Utility Operations 66.6400%

Lincoln production plant structures (excluding bus house), boiler plant, and miscellaneous power plant equipment allocated 50% to electric and 50% to steam heating on the basis of relative monthly peaking capabilities. The electric portion is allocated on the basis of Note 1.

10. Electric - California 3.7045%
- Oregon 58.0851%

All Other Utility Operations 38.2104%

Albany production plant land and tailrace land assigned to electric, remainder of plant allocated to water 8.5% and electric 91.5% on the basis of relative amount of water used. The electric portion is allocated on the basis of Note 1.

11. Electric - California 5.2783%
- Oregon 60.4745%

All Other Utility Operations 34.2472%

Based on directly assigned and allocated gross investment in utility plant excluding allocable items of general office equipment and organization cost.

12. Electric - California 5.3722%
- Oregon 61.5511%
- All Other 33.0767%

Based on directly assigned and allocated gross investment in electric plant excluding allocable items of general office equipment and organization cost.

13. Electric - California .3100%
- Oregon 87.8200%

All Other Utility Operations 11.8700%

Albina Stores structures and land allocated 79% to general stores and 21% to Portland district on basis of area occupied. Portland district is assigned direct. General stores allocated between electric and steam heat on basis of materials stored. Electric portion then allocated on basis of stores issued in 1968.

14. Electric - California 21.1442%
- Oregon 78.8558%

Based on plant in service of the districts in the Southwestern Division at 12-31-77.

15. Electric - California .8610% .832%
- Oregon 13.4999%
- All Other 85.6391%

Based on directly assigned and allocated gross Montana electric utility plant in service at 12-31-77.

Growth Share Allocation

16. Electric - California 65.1242% 65.252%
- Oregon 22.8363%
- All Other 12.0395%

Based on directly assigned and allocated gross California electric utility plant in service at 12-31-77.

17. Electric - California 1.8950% 1.909%
- Oregon 86.5382%

All Other Utility Operations 11.5668%

Based on directly assigned and allocated gross Oregon electric utility plant in service excluding licensed transportation plant at 12-31-77.

17A. Electric - California 3.4675% 3.273%
- Oregon 54.3704%
- All Other 42.1621%

Based on directly assigned and allocated gross Wyoming electric plant in service at 12-31-77.

18. Electric - California 3.1662% 3.298%
- Oregon 49.7708%
- All Other 47.0630%

Based on directly assigned and allocated gross Washington plant in service at 12-31-77.

19. None

20. Electric - California 4.1228%
- Oregon 65.0289%

All Other Utility Operations 30.8483%

Portland office furniture and equipment allocated 14.5% to Portland electric, 1% to Portland steam heating and 84.5% to all utilities on the basis of estimated use. Portion to all utilities is allocated on basis of Note 21.

21. Electric - California 4.8790%
- Oregon 59.7975%

All Other Utility Operations 35.3235%

Based on the average of directly assigned and allocated gross plant investment and operating expenses, excluding general office plant and expenses.

22. Electric - California 4.9906%
- Oregon 61.1882%
- All Other 33.8212%

Based on the average of directly assigned and allocated gross electric plant investment and electric operating expenses, excluding general office plant and expenses.

23. Electric - Oregon 97.3138%

Other Utilities 2.6862%

Based on the average of Oregon directly assigned and allocated gross plant investment and operating expenses, excluding general office plant and expenses.

24. Electric - Montana 97.2227%

Other Utilities 2.7773%

Based on the average of Montana directly assigned and allocated gross plant investment and operating expenses, excluding general office plant and expenses.

25. Electric - Oregon 78.8920%

All Other Utility Operations 21.1080%

Based on the average of Oregon and Washington directly assigned and allocated gross plant investment and operating expenses, excluding general office plant and expenses.

26. Electric - Oregon 76.9573%
- All Other 23.0427%

Based on the average of directly assigned and allocated gross plant investment operating expenses of the above electric systems, excluding general office plant and expenses.

27. None

28. Electric - Oregon 99.0682%

Other Utilities .9318%

Based on the average of directly assigned and allocated gross plant investment and operating expenses, excluding general office plant and expenses.

29. Electric - Oregon 96.8762%

Other Utilities 3.1238%

Based on the average of directly assigned and allocated gross plant investment and operating expenses, excluding general office plant and expenses.

30. Electric - Wyoming 96.5167%

Other Utilities 3.4833%

Based on the average of directly assigned and allocated gross plant investment and operating expenses, excluding general office plant and expenses.

31. None

32. Electric - Oregon 19.2645%

All Other Utility Operations 80.7355%

Based on operating expenses, excluding general office, of Columbia Basin Division districts and departments for the twelve months ended September 30, 1978.

33. Electric - Oregon 91.9007%

Other Utilities 8.0993%

Based on operating expenses, excluding general office, of Mid-Oregon Division districts and departments.

34. All Other Utility Operations 100.0000%

Based on operating expenses, excluding general office, of Wyoming districts and departments.

35. Electric - California 21.1107%
- Oregon 78.8893%

Based on operating expenses, excluding general office, of Southwestern Division districts.

36. None

37. None

38. Electric - Oregon 92.7725%

Steam Heating - Oregon 7.2275%

Based on operating expenses, excluding general office, of Portland District.

39. Electric - California 5.0531%
- Oregon 60.9441%
- All Other 34.0028%

Based on average number of electric customer billings for the twelve months ended September 30, 1978.

40. Electric - California 4.8601%
- Oregon 58.6161%

All Other Utility Operations 36.5238%

Based on average number of customer billings for the twelve months ended September 30, 1978.

41. Electric - Oregon 99.1343%

Steam Heating - Oregon .8657%

Based on the average number of electric and steam heating customer billings in Portland for the twelve months ended September 30, 1978.

42. Electric - California 4.8015%
- Oregon 61.2442%
- All Other 33.9543%

Based on average number of electric customer billings, excluding duplicate billings, for the twelve months ended September 30, 1978.

43. None

44. Electric - California 5.1687%
- Oregon 59.1889%

All Other Utility Operations 35.6424%

Based on directly assigned and allocated operating payroll for the nine months ended September 30, 1978.

45. Electric - California 2.4076%
- Oregon 77.7788%

All Other Utility Operations 19.8136%

Based on directly assigned and allocated operating payroll for the State of Oregon for the nine months ended September 30, 1978.

46. Electric - California 2.3120%
- Oregon 33.3202%

All Other Utility Operations 64.3678%

Based on directly assigned and allocated operating payroll for the State of Washington for the nine months ended September 30, 1978.

47. Electric - California .5742%
- Oregon 7.6536%

All Other Utility Operations 91.7722%

Based on directly assigned and allocated operating payroll for the State of Montana for the nine months ended September 30, 1978.

48. Electric - California 2.9812%
- Oregon 44.0785%

All Other Utility Operations 52.9403%

Based on directly assigned and allocated operating payroll for the State of Wyoming for the nine months ended September 30, 1978.

49. Electric - California 74.3889%
- Oregon 16.6232%
- All Other 8.9879%

Based on directly assigned and allocated operating payroll for the State of California for the nine months ended September 30, 1978.

50. Electric - Oregon 15.3642%
- All Other 84.6358%

Based on average number of electric customer billings, excluding duplicates, in Columbia Basin Division for the twelve months ended September 30, 1978.

51. Electric - California 16.6251%
- Oregon 83.3749%

Based on average numer of electric customer billings, excluding duplicates, in Southwestern Division for the twelve months ended September 30, 1978.

PACIFIC POWER & LIGHT COMPANY
Growth Share Allocation Method

<u>12-31-79 California Capacity Requirements</u>

PP&L 0.04 (Note 1 Ratio) x [5,923.5MW (PP&L Table 3-2) less 26 MW (Libby Plant) less 37 MW (Idaho Requirement)]

= 0.04 x 5860.5MW = <u>234.4MW</u>

<u>12-31-79 California Capacity Supplies</u>

Hydroelectric: 938.5MW (PP&L Table 3-2) x 0.0432 (PP&L 1975 Note 1 Ratio)	= 40.5 MW
1975 Thermal (a): 1374.0 x 0.0432 (PP&L 1975 Note 1 Ratio)	= 59.4
1975 Purchased Power: 1143.1 MW Line 19 on attached x 0.0432 (1975 Purchased Power Ratio)	= 49.4
	149.3 MW
Thermal Plants (b) Built Since 1975: 1627.6MW (PP&L Table 3-2) x 0.03539 (Share calculated to provide difference)	= 57.6 MW
Purchased Power Since 1975: 777.3 Line 19 on attached x 0.03539 (Share calculated to provide difference)	= 27.5
Total Supplies	<u>234.4MW</u>

(a) Centralia, D. Johnston

(b) Wyodak, Jim Bridger, Trojan

PACIFIC POWER & LIGHT COMPANY
Growth Share Allocation Method

1979 California MWh Requirement

Cal. Note 1A Share		Total System Requirements		Idaho Requirement
0.037577 (PP&L Note 1A	x	[25,357,250 MWh (PP&L Table 3-2)	less	188,850 MWh]
= 0.037577	x	25,168,400 MWh		= 945,750 MWh

1979 California MWh Supplies

Hydroelectric:	4,257,450 MWh (PP&L Table 3-2)	x	0.0432 (PP&L 1975 Note 1 Ratio	=	183,920 MWh
1975 Thermal (a):	8,359,280	x	0.039148 (PP&L 1975 Note 1 Ratio	=	327,250
1975 Purchased Power:	4,741,860 MWh Line 19 of attached	x	0.0432 (PP&L 1968 Note 1 Ratio)	=	204,850
					716,020 MWh
Thermal Plants Built Since 1975:	6,974,820 (PP&L Table 3-2)	x	0.02942 (Share calculated to provide difference)	=	205,170
Purchased Power Since 1975:	834,990 Line 19 of attached	x	(Share calculated to provide difference)		24,560 MWh
			Total Supply		945,750 MWh

(a) Centralia, D. Johnston

(b) Wyodak, Trojan, Jim Bridger

Pacific Power & Light Company
Purchased Power - Net Interchange

		1975 Rate Case		1979 Rate Case			
		MW	MWh	$	MW	MWh	
	5 State System						
1.	BPA- Supplemental Capacity	70.4	-	292,146	49.8	-	
2.	BPA- Entitlement Capacity	-	-	292,146	-	-	
3.	Hanford - WPPSS	19.4	612,000	506,800	20.2	625,130	
4.	Hanford - Extension	84.0		3,710,804	84.0		
5.	CSPE	104.3	851,100	1,938,669	147.0	502,640	
6.	Priest Rapids-Grant Co.	246.1		2,629,004	168.3		
7.	Wanapum-Grant Co.	327.4	3,861,900	3,424,696	220.1	3,009,760	
8.	Rock Beach	75.9		1,217,616	68.1		
9.	Wells	93.5		1,553,772	87.6		
10.	Swept #2	76.7	230,700	1,404,000	76.7	220,390	
11.	Talent	18.3	84,100	487,548	18.3	67,100	
12.	Miscellaneous Contracts			506,768	-	106,840	
13.	Cove - PG&E	3.0	24,000	70,332	3.0	24,000	
14.	Peak Capacity -BPA	200.0	-	2,400,000	200.0	-	
15.	Secondary Purchases	-	178,100	578,228	-	178,100	
16.	Interchange - Received	-	7,900	90,850	-	7,500	
17.	Interchange - Delivered						
18.	Subtotal (1975 Bases)	1,319.0	5,849,800	21,103,379	1,143.1	4,741,860	
19.	California Share @ 0.0432	-	-	911,666	49.4	204,850	
	Remaining Purchased Power						
20.	Jim Bridger Test Energy			3,309,975	-	220,670	
21.	Peak Capacity			4,827,600	477.3	-	
22.	Peak/Energy Exchange			-	300.0	(711,300)	(Valued @3.0 mills/kWh)
23.	Secondary Energy			6,555,702	-	2,019,220	
24.	Interchange - Received			(7,286,400	-	(633,600)	
25.	Interchange - Delivered						
26.	Subtotal - Remainder			7,406,877	777.3	834,990	
27.	Allocated to Peak			7,141,500	777.3	-	
28.	Allocated to Energy			265,377	-	834,990	
29.	California Share @ 0.03539			252,738	27.5	-	
30.	California Share @ 0.02942			7,807	-	24,560	
31.	Total California Share			1,172,211	76.9	229,410	(Lines 19+29+30)

2.38605 /RJJ/km/ec

California and Oregon Residential Rates Compared for Homes with No Electric Water or Space Heat

WINTER SIX MONTHS

(1) KWs Used	(2) $ For Each Add'l 1,000 kWh Calif.	(3) Total Calif. Accumu-lative	(4) $ For Each Add'l 1,000 kWh Oregon	(5) Total Oregon Accumu-lative	(6) Calif. Over Oregon	(7) % Calif. Over Oregon
1,000 kW.	$37.34	$ 37.34	$33.04	$ 33.04	$ 4.30	13.0%
2,000 kW.	37.70	75.04	30.04	63.08	11.96	19.0
3,000 kW.	37.70	112.74	30.04	93.12	19.62	21.1
4,000 kW.	37.70	150.44	30.04	123.16	27.28	22.2
5,000 kW.	37.70	188.14	30.04	153.20	34.94	22.8

SUMMER SIX MONTHS

(1) KWs Used	(2) $ For Each Add'l 1,000 kWh Calif.	(3) Total Calif. Accumu-lative	(4) $ For Each Add'l 1,000 kWh Oregon	(5) Total Oregon Accumu-lative	(6) Calif. Over Oregon	(7) % Calif. Over Oregon
1,000 kW.	$37.34	$ 37.34	$30.31	$ 30.31	$ 7.03	23.2%
2,000 kW.	37.70	75.04	27.31	57.62	17.42	30.2
3,000 kW.	37.70	112.74	27.31	84.93	27.81	32.7
4,000 kW.	37.70	150.44	27.31	112.24	38.20	34.0
5,000 kW.	37.70	188.14	27.31	139.55	48.59	34.6

California and Oregon Residential Rates Compared for Homes with Electric Water Heat but without Electric Space Heat

WINTER SIX MONTHS

(1) KWs Used	(2) $ For Each Add'l 1,000 kWh Calif.	(3) Total Calif. Accumu-lative	(4) $ For Each Add'l 1,000 kWh Oregon	(5) Total Oregon Accumu-lative	(6) Calif. Above Oregon	(7) % Calif. Above Oregon
1,000 kW.	$32.72	$ 32.72	$33.04	$ 33.04	$-0.32	- 1.0%
2,000 kW.	37.70	70.42	30.04	63.08	7.34	11.6
3,000 kW.	37.70	108.12	30.04	93.12	15.00	16.1
4,000 kW.	37.70	145.82	30.04	123.16	22.66	18.4
5,000 kW.	37.70	183.50	30.04	153.20	30.30	19.8

SUMMER SIX MONTHS

(1) KWs Used	(2) $ For Each Add'l 1,000 kWh Calif.	(3) Total Calif. Accumu-lative	(4) $ For Each Add'l 1,000 kWh Oregon	(5) Total Oregon Accumu-lative	(6) Calif. Above Oregon	(7) % Calif. Above Oregon
1,000 kW.	$32.72	$ 32.72	$30.31	$ 30.31	$ 2.41	8.0%
2,000 kW.	37.70	70.42	27.31	57.62	12.80	22.2
3,000 kW.	37.70	108.12	27.31	84.93	23.19	27.3
4,000 kW.	37.70	145.82	27.31	112.24	33.58	29.9
5,000 kW.	37.70	183.50	27.31	139.55	43.95	31.5

California and Oregon Residential Rates
Compared for Homes with Electric Space and Water Heat

WINTER SIX MONTHS

(1) KWs Used	(2) $ For Each Add'l 1,000 kWh Calif.	(3) Total Calif. Accumu-lative	(4) $ For Each Add'l 1,000 kWh Oregon	(5) Total Oregon Accumu-lative	(6) Calif. Above Or Below Oregon $	(7) Calif. Above Or Below Oregon %
1,000 kW.	$21.99	$ 21.99	$33.04	$ 33.04	$-11.05	-33.4%
2,000 kW.	24.85	46.84	30.04	63.08	-16.24	-25.7
3,000 kW.	37.70	84.54	30.04	93.12	- 8.58	- 9.2
4,000 kW.	37.70	122.24	30.04	123.16	- 0.92	- 0.7
5,000 kW.	37.70	159.94	30.04	153.20	6.74	4.4

SUMMER SIX MONTHS

(1) KWs Used	(2) $ For Each Add'l 1,000 kWh Calif.	(3) Total Calif. Accumu-lative	(4) $ For Each Add'l 1,000 kWh Oregon	(5) Total Oregon Accumu-lative	(6) Calif. Above Or Below Oregon $	(7) Calif. Above Or Below Oregon %
1,000 kW.	$32.72	$ 32.72	$30.31	$ 30.31	$ 2.41	8.0%
2,000 kW.	37.70	70.42	27.31	57.62	12.80	22.2
3,000 kW.	37.70	108.12	27.31	84.93	23.19	27.3
4,000 kW.	37.70	145.82	27.31	112.24	33.58	29.9
5,000 kW.	37.70	183.52	27.31	139.55	43.97	31.5

SOURCE: EXHIBIT 51

A.58605 /ALJ/km

APPENDIX J

SOUTHERN CALIFORNIA EDISON
MONTEBELLO DISTRICT

PLEASE RETURN THIS PORTION
MAIL PAYMENT TO
P.O. BOX 600, ROSEMEAD, CALIF. 91771

BILL S. NEW
POST OFFICE BOX 12345
LEBEC, CALIFORNIA 92640

PLEASE PAY THIS AMOUNT NOW DUE

12 22 604 3500 01 000033 00005915 31124 $59.15

SOUTHERN CALIFORNIA EDISON

KEEP THIS PORTION FOR YOUR RECORDS

SERVICE ADDRESS	FOR BUSINESS OFFICE CALL	YOUR ACCOUNT NUMBER IS	DATE BILL PREPARED
BILL S. NEW 1000 EDISON PLACE, APARTMENT 0-123 LEBEC, CALIFORNIA 92640	209-000-0000 209-000-0000	12-22-604-3500-01	11-02-78

LIFELINE ALLOCATION	RATE SCHEDULE	AVERAGE DAILY COST	BILLING PERIOD	DAYS	KWH USAGE	DAILY AVERAGE
480 KWH	D-3	$.94	THIS YEAR	60	1250	20.8 KWH
			LAST YEAR	61	1446	23.7 KWH

TYPE OF SERVICE	METER NUMBER	SERVICE PERIOD FROM	SERVICE PERIOD TO	METER READING FROM	METER READING TO	ENERGY USAGE	AMOUNT
* ELECTRIC	CEP-307845	09-01-78	10-31-78	00100	01350	1250 KWH	$56.34
						LEBEC CITY TAX 5 %	2.81

ELECTRIC SERVICE CHARGE = 1.50
FIRST 240 KWH AT 2.595¢ = 6.23
NEXT 260 KWH AT AVG COST 2.472¢ = 6.43
USE LESS ENERGY AND ENJOY LOWER RATES

* STATE ENERGY TAX OF $.010 PER 100 KWH INCLUDED WITH ELECTRIC CHARGE

PLEASE PAY THIS AMOUNT NOW DUE $59.15

RECENT PAYMENTS MAY NOT HAVE BEEN DEDUCTED FROM THIS BILL

CUSTOMER MESSAGE

* Message for average lifeline customer using 500 Kwh electricity. These quantities do not match billed totals, but are used only as examples.