(Decision No. C81-1282)

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

***

IN THE MATTER OF THE PROPOSED INCREASED RATES AND CHARGES CONTAINED IN TARIFF REVISIONS FILED BY PUBLIC SERVICE COMPANY OF COLORADO, 550 15TH STREET, DENVER, COLORADO, UNDER ADVICE LETTER NO. 795 - ELECTRIC, ADVICE LETTER NO. 296 - GAS, AND ADVICE LETTER NO. 24 - STEAM.	INVESTIGATION AND SUSPENSION DOCKET NO. 1425 DECISION AND ORDER OF THE COMMISSION PHASE II

July 21, 1981

P R E C I S

AVERAGE AND EXCESS DEMAND WITH NON-COINCIDENT PEAK METHOD ADOPTED FOR DEMAND ALLOCATION; STAFF PROPOSED TWO-PART RATE FOR RESIDENTIAL AND SMALL COMMERCIAL CUSTOMERS ADOPTED, TIME OF DAY RATES FOR LARGE CUSTOMERS (4 MW AND ABOVE) ADOPTED; THREE RATING PERIODS ADOPTED; STAFF PROPOSED RATE DIFFERENTIAL ADOPTED; 5% CONSERVATION EFFECT REJECTED; OTHER INTERVENOR-PROPOSED CHANGES REJECTED.

Appearances:

Kelly, Stansfield and O'Donnell by
James R. McCotter, Esq., and
James K. Tarpey, Esq.,
Denver, Colorado, for
Public Service Company of Colorado,
Respondent;

Gorsuch, Kirgis, Campbell, Walker & Grover
by Leonard M. Campbell, Esq., and
William H. McEwan, Esq.,
Denver, Colorado, for
AMAX, Inc.;

D. Bruce Coles, Esq.,
Denver, Colorado, for
Colorado Association of Community
Organizations for Reform Now,
Colorado Energy Advocacy Office, and
The United Food and Commercial Workers,
Local 7;

Richard L. Fanyo, Esq., and
Randall J. Feuerstein, Esq.,
Denver, Colorado, for
CF&I Steel Corporation;

James M. Lyons, Esq.,
Denver, Colorado, for
Home Builders Association of
Metropolitan Denver;

John L. Mathews, Esq.,
San Francisco, California,
Western Area Chief Counsel
for Regulatory Law, General
Services Administration for the
Executive Agencies of the United States;

Jeffrey G. Pearson, Esq.,
Daniel Kogovsek, Esq., and
Suzanne Schiro, Esq.,
Denver, Colorado, for
Colorado Office of Consumer Services
and Peoples Utility Alliance;

Jeffrey Pond, Esq.
Denver, Colorado,
for Ideal Basic Industries, Inc.;

C. Paul Swift, Esq.
Denver, Colorado,
for Abex Corporation;

Steven H. Denman, Esq.,
Dudley P. Spiller, Esq., and
Tucker K. Trautman, Esq.,
Denver, Colorado, for
the Staff of the Commission;

John E. Archibold, Esq.,
Denver, Colorado, for
The Commission.

I N D E X

BY THE COMMISSION:

I. HISTORY OF THE PROCEEDINGS

On May 7, 1980, Public Service Company of Colorado (hereinafter "Public Service", or "Company", or "Respondent") filed with the Commission three advice letters, one pertaining to electric rates, one pertaining to gas rates, and one pertaining to steam rates. The three advice letters are as follows:

1. Advice Letter No. 795 - Electric, which is accompanied by 241 tariff sheets, Colorado, P.U.C. No. 6 - Electric cancels Colorado P.U.C. No. 5 - Electric;

2. Advice Letter No. 296 - Gas, which is accompanied by 128 tariff sheets, Colorado P.U.C. No. 5 - Gas cancels Colorado P.U.C. No. 4 - Gas, and

3. Advice Letter No. 24 - Steam, which is accompanied by 4 tariff sheets, pertaining to Colorado P.U.C. No. 1 - Steam.

With respect to the filing made pursuant to Advice Letters No. 795-Electric, No. 296-Gas, and No. 24-Steam, Public Service requested the Commission immediately suspend the filing and establish procedural and hearing dates in order that rates resulting from the filing be effective at as early a date as possible.

The increases initially requested by Public Service in this docket for electric, gas and steam rates are as follows:

Operations	($) Increase	(%) Increase
1. Electric	$161,286,000	31.7%
2. Gas	17,424,000	4.1%
3. Steam	966,000	16.3%
4. Total	$179,676,000	19.6%

On May 27, 1980, in I & S Docket No. 1420, (the so called "emergency increase docket") the Commission authorized emergency rate increases for Public Service's electric, gas and steam operations, as follows:*

		I & S 1420 Authorized	
Operations		($) Increase	(%) Increase
1.	Electric	$45,897,349	9.58%
2.	Gas	9,890,990	2.42%
3.	Steam	618,148	10.66%
4.	Total	$56,406,487	6.20%

The Commission having granted the above emergency increases, under consideration in I & S Docket No. 1425 was Public Service's claim to the remaining amount requested, totaling $121,110,340, calculated as follows:**

Breakdown of Amount Requested by Public Service In Excess of I&S 1420 Granted Increases

Operations		Total ($) Requested	Emergency ($) Increase	Additional Amount Sought
1.	Electric	$158,299,655	$45,897,349	$112,402,306
2.	Gas	17,968,543	9,890,990	8,077,553
3.	Steam	1,248,629	618,148	630,481
4.	Total	$177,516,827	$56,406,487	$121,110,340

*Decision No. C80-1039 (May 27, 1980), pp 19-21.

**Public Service's initial filing was based on 10 months actual and two months estimated (Exh. 22, p.1; Exh. D, p.6) for the test year ended June 30, 1980. Subsequently, Public Service witness Midwinter amended the Company's filing to represent 12 months actual for said test year (Exh. 33, p.1; Exh. H, p.6). The above calculation of excess request, totaling $121,110,340, is based on the Company's 12 month actual presentation.

As indicated above with respect to the filings herein, Public Service requested that the said filings be suspended immediately by the Commission and that procedural and hearing dates be established in order that rates resulting from this filing could become effective on as early a date as possible. Public Service further requested that in order to expedite the procedure the Commission staff immediately begin the audit of the Company's books and records.

Public Service requested that the revenue requirements and rate design phases of hearings be separated into two phases and that the revenue increases resulting from an order in Phase I be allowed to become effective immediately upon the completion of Phase I. They further requested that such increase be in the form of a uniform percentage rider applicable to all classes of service pending resolution of any rate design issues.

Public Service also stated that the Company believed the revenue increases resulting from the filed tariff sheets would not cause it to exceed the gross margin standard applicable to utilities under the regulations adopted by the President's Council on Wage and Price Stability.

On May 20, 1980, the Commission entered Decision No. C80-992 wherein it set the tariff revisions filed by Public Service with respect to its Advice Letters No. 795-Electric, No. 296-Gas, and No. 24-Steam for hearing to commence on September 15, 1980.

Pursuant to the provisions of CRS 1973, 40-6-111(1), the effective date of the tariffs filed by the above mentioned advice letters was suspended until January 7, 1981, or until further order of the Commission.

Also by Decision No. C80-992, the Commission determined that the proceedings would be conducted in two phases: Phase I would consider the revenue requirement of the Company and Phase II would consider the spread of the rates issues.

The hearings in Phase I (the "revenue requirement" phase) were conducted during the fall of 1980.

On December 12, 1980, the Commission entered its Decision and Order in Phase I. On January 6, 1981, the Commission entered Decision No. C81-34 granting in part and denying in part applications for rehearing, reargument and reconsideration. Further requests for reconsideration, reargument or rehearing were denied by Decision No. C81-77, dated January 13, 1981 and Decision No. C81-105, dated January 15, 1981.

The Phase II hearings initially were scheduled to commence on March 4, 1981. However, the hearing dates of March 4, 5 and 6, 1981 were vacated and the hearing in Phase II commenced on March 11, 1981. Hearings were held on March 11, 12 and 13, 1981; on April 22, 23 and 24, 1981; April 29 and 30, 1981; and on May 1, 6 and 7, 1981.

Public Service presented as its direct witnesses in Phase II: J. D. Heckendorn and J. H. Ranniger.

The Staff of the Commission ("Staff") presented as its witnesses: Bruce Mitchell, Ernest Tronco and George Parkins.

Intervenors Colorado Association of Community Organizations for Reform Now, Colorado Energy Advocacy Office, and The United Food and Commercial Workers, Local 7 (hereinafter collectively "CEAO") presented as their witness: Eugene Coyle.

Intervenor AMAX, Inc. ("AMAX") presented as its witnesses: Charles Chick and Jan Michael.

General Services Administration ("GSA") presented as its witnesses: Joseph A. Herz and Harbans S. Chhabra.

The Office of Consumer Services ("OCS") presented as its witness: M. J. Ileo.

On rebuttal Public Service presented as its witnesses: Thomas Boardman, J. D. Heckendorn and J. H. Ranniger.

CEAO presented as its rebuttal witness: Eugene Coyle.

All prefiled written direct testimonies were marked as exhibits using letters of the alphabet. All exhibits filed with and in support of written direct testimony were marked using arabic numerals. Both the letters and numerals were preceded by Roman Numeral II. Public witness exhibits were so identified. The list of exhibits is appended to the Decision as Appendix A.

Initial statements of position with regard to Phase II were filed by:

Home Builders Association of Metropolitan Denver	May 29, 1981
City of Grand Junction and County of Mesa	June 1, 1981
General Services Administration	June 1, 1981
Abex Corporation	June 1, 1981
Colorado Energy Advocacy Office, ACORN and UFCW Local 7	June 1, 1981
Staff of the Commission	June 1, 1981
CF&I Steel Corporation	June 1, 1981
AMAX, Inc.	June 1, 1981
Public Service Company of Colorado, Respondent	June 1, 1981
Office of Consumer Services and Public Utility Alliance	June 4, 1981

Reply statements of position which were to be filed on or before June 22, 1981 were filed by the following:

CEAO, ACORN and UFCW Local 7	June 22, 1981
GSA	June 22, 1981
OCS and Peoples Utility Alliance	June 22, 1981
AMAX, Inc.	June 22, 1981
Public Service Company of Colorado, Respondent	June 22, 1981

Phase II - Final Decision and Order

The Commission on December 12, 1980, authorized Public Service to place into effect new rates based upon its then current rate structure and the revenue requirement as found in Phase I. The Commission considered those rates as final rates for administrative and judicial review purposes. Rates which we shall hereinafter order, as a result of the Phase II hearings herein, shall reflect the overall revenue requirement initially found in Phase I. These rates also shall be considered final for the purposes of the procedural provisions of C.R.S. 1973, 40-6-114 and 40-6-115.

Submission

The herein instant matter has been submitted to the Commission for decision. Pursuant to the provisions of the Colorado Sunshine Act of 1972, C.R.S. 1973, 24-6-401, et seq., and Rule 32 of the Commission's Rules of Practice and Procedure, the subject matter of this proceeding has been placed on the agenda for an open meeting of the Commission. At an open meeting the herein Decision was entered by the Commission.

II. PRELIMINARY REMARKS

Public Service's electric, gas and steam customers presently are subject to base rates established in Investigation and Suspension Docket No. 1330 plus two add-on riders. By Decision No. C80-1039, dated May 27, 1980, in Investigation and Suspension Docket No. 1420, the Commission authorized riders in the amount of 9.58% for electric, 2.42% for gas, and 10.66% for steam rate schedules, respectively. By Decision No. C80-2346, dated December 12, 1980, the Commission authorized the second set of riders in the amount of 5.5% for electric, .18% for gas, and 8.78% for steam rate schedules, respectively.

The purpose of Phase II in Investigation and Suspension Docket No. 1425 is to translate the revenue requirement previously found in Phase I of this Docket into appropriate spread of the rates among Public Service's various class of customers for its various commodities (electricity, gas, and steam).

No objections were raised concerning Public Service's proposals for allocating costs or designing rates with respect to its steam customers. Public Service's proposed steam rates provide for an $80 minimum monthly rate plus a declining block rate depending upon the number of pounds used per 1,000 pounds. We find that the tariffs set forth in Exhibit II-8 are just and reasonable and should be adopted by the Commission.

With respect to the gas department, Public Service allocated costs and designed rates in accordance with the criteria established by the Commission in Investigation and Suspension Docket No. 1330. In that Docket, the Commission adopted the so-called United methodology wherein fixed costs are allocated 75% to the commodity rate and 25% to the demand rate.*

---

* The so-called United formula was adopted In re: United Gas Pipeline Company by the Federal Power Commission in Opinion No. 671 on October 31, 1973, 3 PUR 4th 491. For a more extended discussion of gas cost allocation, see Decision No. C80-130, dated January 22, 1980, Pages 56-58.

In this cost allocation process, interruptible industrial customers receive no demand allocation, in recognition of their interruptible status, although they are assessed 75% of the fixed charges through the commodity rate.

Similarly, residential gas rates were designed in accordance with Investigation and Suspension Docket No. 1330. Specifically, residential gas rates were designed on the basis of a monthly service charge recovering only expenses incurred in connection with meter reading and billing (exclusive of fixed charges attributable to customer specific investment) and a flat per CCF charge designed to recover commodity, demand and the balance of customer charges. In addition, the availability of additional cost of service data enabled Public Service to reduce the number of gas rate areas from 8 to 5.

We find that the gas tariffs set forth in Exhibit II-7 are just and reasonable and should be adopted by the Commission.

The only controverted issues in Phase II Investigation and Suspension Docket No. 1425 involved Public Service's electric rate proposals. Even in this area, there were a number of specific rates which did not engender any controversy among the parties, such as the interruptible industrial rates, interruptible irrigation pumping service rates, and curtailable air conditioning rates, among others. These rates, of course, are designed to reduce overall and peak load and are in accord with Commission policy as set forth in the so-called "Generic Decision".* Accordingly, except as hereinafter indicated in this Decision and Order, the Commission finds that the electric rate proposals filed by Public Service are just and reasonable and should be adopted by the Commission.

---

*Decision No. C79-1111, dated July 27, 1979, in Case No. 5693 in which a wide range of policy issues were addressed and policy guidelines set forth bearing on achieving goals of conservation, efficiency, and equity.

In the succeeding portions of the Decision herein, the Commission will discuss some of the controverted issues which require resolution in Phase II of this Docket.

III. COST OF SERVICE: DEMAND ALLOCATION METHODOLOGIES

A number of separate demand allocation methodologies were presented during Phase II. Public Service proposed the average and excess demand method (AED) with the excess allocated on the basis of <u>non-coincident</u> peak demand. Technically, Public Service stated that because of the necessity to synchronize cost allocation with the possible advent of time-of-day (TOD Rates), the group maximum demands used to allocate the excess demands were those occurring during peak hours, as defined by Public Service, of 8 a.m. to 11 p.m. CEAO's witness, Dr. Coyle, proposed an AED method with the excess allocated on the basis of <u>coincident</u> peak demand.

AMAX witness Chick proposed the adoption of the Peak and Average method which essentially derives the demand related allocation percentages for each class by adding the class contribution to the system peak demand to the class average demand and using the sum as the allocation basis. This method accords less weight to energy consumption than does Public Service's proposed methodology. Mr. Chick stated in his prepared testimony that the results of his proposal would not produce substantially different results than the AED Method proposed by Public Service, but it would have the effect of being compatible with the possible adoption of TOD Rates and would provide appropriate incentives to customers on a TOD Rate to shift energy consumption.

A third AED Method received considerable attention during the course of the Phase II hearings. This third AED Method allocated the excess component derived on the basis of the average class contribution to the summer and winter system peaks.*

---

*CEAO witness Coyle suggested a weighted average for the summer and winter peaks with a 60% weighting being applied to the summer peak and 40% to the winter peak.

Public Service, the Staff and Intervenor CF&I Steel Corporation ("CF&I") proposed the adoption of the AED with coincident peak method. AMAX proposed the adoption of the Peak and Average Method and CEAO proposed the adoption of the AED with coincident peak method. CF&I states that were the Commission not to adopt the AED with non-coincident peak method that its next preference would the Archibold Twin Peak Method. Likewise, AMAX states that if the Commission were not to adopt the Peak and Average Method, its next choice would be the Archibold Twin Peak Method. CEAO appears to adopt the Coyle dual peak variation of AED as its second choice. Public Service indicated that in the event the Commission did not fully and finally endorse the continued use of the AED with non-coincident peak methodology historically utilized by the Company, the Twin Peak proposal should be given additional consideration in future rate cases.

It goes without saying that there are a number of possible methodologies for allocating demand. In the last analysis, it is a matter of judgment considering various strengths and weaknesses of the different methodologies for the Commission to determine which methodology, over all, is best suited to the particular utility involved. On balance, in light of the relatively recent shift of Public Service to a summer peaking utility, the small differential between its summer and winter peaks, and the number of new initiatives presently being undertaken with peak restraint in mind, the Commission finds that the AED with non-coincident peak method as traditionally used by Public Service in the past should be continued. We do not find it is appropriate to allocate excess demands during Public Service's defined peak hours of 8 a.m. to 11 p.m. Given Public Service's high load factor and levelized load characteristics, the standard version of the AED with non-coincident peak methodology is the most appropriate in that it gives consideration to customers' annual load factor as well as their maximum demand placed upon the system. The non-coincident peak methodology avoids difficulties which might arise by giving undue attention to what happens to transpire on the system peak day. The AED with coincident peak method advocated by CEAO witness Coyle presently would benefit the residential class because Public Service in recent years has been a summer peaking company. Inasmuch as residential customers are not primarily responsible for the summer peak, the AED methodology which allocates the excess on the basis of coincident peak method would allocate more of the demand costs to the summer peaking customers. However, a leveling of summer demands, coupled with an increase in winter demands experienced by Public Service, could result in radical shifts in the demand related allocation results from year to year. This very real possibility would result in severe customer dislocation and undermine revenue stability. Inasmuch as Public Service is introducing curtailable air conditioning and interruptible rates, for the purpose of reducing the level of the Company's summer peak demand, it cannot be assumed, given the relatively small differential now existing between summer and winter peaks, that Public Service in the future might not again be a winter peaking company.

Another difficulty with the coincident peak AED method is the fact that a customer could place a heavy demand on the Company's system off peak. Under the coincident peak AED method, this off-peak customer gets a "free ride" with respect to his excess demand. In light of Public Service's load configuration the Commission does not believe that such an allocation is equitable.

In the event Public Service's load configuration should change in the future, the Commission, at that time, would have the option to reconsider the appropriate demand allocation methodology. On balance, the Commission believes that the continuation of the AED method with non-coincident peak represents the best allocation methodology applicable to Public Service at this time. We do not find it appropriate, as proposed by Public Service, to allocate excess demands only during Public Service's defined peak hours of 8 a.m. to 11 p.m.

IV. COST OF SERVICE: OTHER ALLOCATION ISSUES

A. Allocation of Income Taxes

CEAO witness Coyle questioned the method used by Public Service in allocating State and Federal income taxes to the various rate classifications. Dr. Coyle proposed that income taxes be allocated on the basis of the class net plant ratios. Public Service, with Commission approval, historically has allocated income taxes to the various rate classifications on the basis of taxable income. Dr. Coyle criticized this approach on the basis that certain customer classes are assigned negative income taxes and low-earning classes pay lesser taxes, thus rewarding the unremunerative customers on the system. However, as AMAX witness, Mr. Chick, pointed out in criticism of Dr. Coyle's proposed allocation procedure, Dr. Coyle's method is based on a premise that any class would be considered to have a cost responsibility for income taxes proportional to that class's allocation of net plant, regardless of the magnitude of that class's contribution to the taxable income of the Company. As Mr. Chick explained, painstaking efforts are undertaken in the cost of service study to allocate investment and cost to the various rate classes on the basis of the cost causative characteristics incurred by the Company for which various rate classes should properly be responsible. Income taxes are paid by the Company on the basis of taxable income and, consistent with the basic premise of any cost allocation study, responsibility for these income taxes should then be allocated to the various rate classes on the basis of their respective contribution to taxable income. Thus, we find that the income tax allocation procedure used by Public Service follows the cost causative incidence and results in a fair and equitable allocation among the rate classes. Dr. Coyle's proposal would not recognize this basic premise of cost allocation and would assign income tax responsibility to the various rate classes based upon a procedure which is not relevant to the cost causative characteristic underlying Public Service's responsibility for the paying of income taxes.

It also must be recognized that inasmuch as Public Service is a combination utility providing both electric and gas service, the electric and gas departments, respectively are entitled to different tax treatment for certain specific activities. For example, if the electric department has a large interest deduction resulting from power plant construction, that deduction should flow to the electric rate payers of the company and should not be shared on a net plant basis with gas ratepayers which may be an inherent result of Dr. Coyle's proposal. Accordingly, we find that no change in Public Service's allocation methodology for income taxes should be made.

B. Allocation of Coal Cars and Coal Stocks

CEAO witness Dr. Coyle, recommended that the investment in Public Service's coal cars and coal stocks be allocated on the basis of energy and not demand. Dr. Coyle's support for this proposal seems to be that Public Service has made an investment in coal cars to achieve a lower cost of energy. However, Public Service witness Ranniger, in his rebuttal testimony, advocated the continued allocation of the investment in coal cars and coal stocks on the basis of demand-related class responsibility.

The Commission agrees that allocation of the investment in coal cars and coal piles on the basis of demand-responsibility better reflects cost causative characteristics. The investment in coal cars in integrally associated with the investment in generating plant and, as Mr. Ranniger explained, that investment is treated as a rate base item for revenue requirement purposes. Moreover, the allocation of the investment in coal cars on the basis of demand-related responsibility is also consistent with investment in the coal handling equipment at the coal handling site which is clearly allocated on the basis of demand-related responsiblity. Thus we find that the investment in coal cars and coal stocks should be allocated, as advocated by Public Service, on the basis of class demand-related responsibility.

C. Allocation of General and Common Plant and Other Certain Expenses

Public Service's methodology for allocation of general and common plant, administrative and general expenses, operation and maintenance expenses, customer services and sales expenses is set forth in Exhibit II-11.

Public Service allocated common and general plant on the basis of functional plant ratios, i.e., in proportion to the summation of allocated production, transmission and distribution plant. GSA witness, Mr. Herz, favored allocating general and common plant on the basis of wage and labor ratios rather than on plant ratios. It is his contention that an allocation on the basis of plant ratios results in an inequitable distribution of common and general plant, whereas the use of labor ratios more closely relates the functional use of common and general plant facilities. Stated another way, GSA believes that common and general plant involves the use of people-related assets.

Mr. Herz also advocated that administrative and general expenses, excluding property insurance, should be allocated on the basis of wage and labor ratios since these expenses are predominantly "people-related". Public Service, on the other hand, allocates administrative and general expense, excluding property insurance, in proportion to the total of transmission operation and maintenance expense, distribution operation and maintenance expense, customer accounting expense, and property taxes.

Mr. Herz further advocated that customer services and sales expenses should be allocated on the basis of weighted customer ratios rather than energy ratios, and he therefore allocated expenses on a weighted customer basis, using a weighting factor of 100 residential customers to one large power user. The net effect of Mr. Herz's procedure is that, on a customer basis, the industrial user is allocated 100 times more cost than a residential customer. Public Service, on the contrary, allocates customer service expense, including sales expense, in proportion to the adjusted annual kilowatt hours shown on the "determination of average and excess demand" page of its cost of service study.

As can be seen from the foregoing, there are a number of alternative methods of allocating common and general plant, as well as administrative and general expenses, operation and maintenance expenses, and customer services and sales expenses. It is a matter of judgment as to which allocation procedure should be used with respect to categories of plant or categories of expense. On balance, we find that the allocation methodologies used by Public Service, as set forth in Exhibit II-11, are reasonable and should be adopted. Absent a showing that the Public Service methodologies are contrary to the public interest, we find no basis to substitute our judgment for that of the Company in this regard. Accordingly, the Commission accepts the allocation methodologies of Public Service with regard to common and general plant, administrative and general expenses, operations and maintenance expenses, and customer services and sales expenses, respectively.

V. RESIDENTIAL AND SMALL COMMERCIAL RATE DESIGN

In its filing, Public Service proposed, in accordance with one of the alternatives of the Commission's generic decision, a three-part rate, comprised of a service charge, a demand charge with a declining block feature, and a flat energy charge (the "R" rate). Although this rate is highly cost tracking, it was also apparent that it would have a substantial impact on low usage residential customers. Accordingly, prior to the commencement of the hearings in Phase II, Public Service filed and served alternate rate design proposals. Public Service Alternate No. 1 was in the form of the currently effective declining block rate; Public Service Alternate No. 2 was comprised of a service charge recovering all customer service expenses and a flat per kilowatt hour (kwh) rate recovering demand and energy costs; Public Service Alternate No. 3 was a modification of the originally filed R rate with a demand charge adjusted to make the total charge in the tail block the same as under Public Service Alternate No. 2.

Public Service witness Ranniger sponsored Exhibit II-28 comparing the charges under the various Public Service alternatives at different usage levels, and he explained at length the advantages and disadvantages of each. Mr. Ranniger maintained that because of the conservation incentive contained in Public Service Alternate Rate No. 2 and because each kilowatt hour sold would have to recover not only energy costs but some demand costs as well, the rate set forth in Public Service Alternate No. 2 was designed on the basis of an assumed five percent reduction in consumption in order to keep Public Service whole with respect to its fixed costs. Public Service stated that if the five percent conservation assumption were to be adopted by the Commission, the Company would be willing to undergo an after the fact audit to assure that it did not earn in excess of its authorized rate of return during any period when the rates were in effect.

Staff witness, Mr. Tronco, and OCS witness, Dr. Ileo, suggested variations of the two-part rate, with the principal difference being a smaller service charge and the elimination of the five percent conservation feature.

Public Service indicates that it would be willing to adopt a two-part rate form only if it contains the charges set forth in its Alternate No. 2. Public Service claims that the customer service charge proposed by Mr. Tronco and Dr. Ileo increases, to an unacceptable level, the risk inherent in any rate involving a flat charge. Public Service maintains that with a service charge that does not recover all customer-related costs, the kilowatt hour charge must be raised to recover the balance which not only increases the fixed cost to be recovered with each kilowatt hour sold, but also itself encourages the likelihood of conservation. Thus, Public Service maintains, the compound effect is to create a substantial risk that a significant amount of fixed costs will not be recovered. Public Service also maintains that even with a fully-tracking customer service charge, utilization of the five percent conservation assumption is necessary to provide a modicum of protection against revenue erosion resulting from conservation.

The Commission finds that the Staff proposed two-part rate composed of a customer service charge and flat energy charge for both the residential general and small commercial classes is appropriate. We further find that the Staff's proposed residential and small commercial rates are generally cost-tracking, representing a phased increase to each class, and may very well encourage a measure of conservation by Public Service's customers. For the residential general class, the Staff proposed a $2.81 service charge and a commodity charge of $.04673 per kilowatt hour. This rate, of course, contrasts with Public Service's filed "R" rate which is a three-part rate composed of a $2.81 customer service charge, a three-part declining demand charge, and a flat energy charge. The Staff proposed rate is similar to the rate proposed for the general residential class by OCS. OCS proposed a two-part rate with a customer service charge of $2.65 and a flat commodity charge of $.047085 per kilowatt hour.

Under the Public Service's filed R rate, customers using 100 kwh or less per month would have bills with increases substantially in excess of the proposed 14.9% increase in revenue being proposed for this class. The Staff proposed two-part rate lies between Public Service's filed R rate and Public Service's existing declining block rate at lower usage levels. The Staff proposal thereby lessens the impact of fully cost-tracking rates on lower use customers. In other words, the impact of the Staff-proposed two-part rate is less severe on lower use customers than the impact of Public Service's filed "R" rate. The Staff proposed two-part rate is very close to Public Service's filed R rate at average usage levels and is slightly higher at high usage levels.

Another salutary feature of the Staff two-part rate is that it maintains the consistency with the AED methodology wherein the average portion of the allocation is directly proportional to kilowatt hour usage. The excess portion of the allocation is at least partially related to the kilowatt hour usage since it is related to the noncoincident group peak and contribution to this peak is linearly related to kilowatt hour usage. Thus, compared with Public Service's three-part rate, a two-part rate represents more accurately the costs associated with serving the residential class over the entire range of usages.

The Staff also proposed a two-part rate for the small commercial class. The Staff proposed rate contains a customer service charge of $2.81 and a flat commodity charge combining demand and energy charges of $.04264 per kilowatt hour. This compares with Public Service's filed C rate that features a $2.81 service charge, a three-part declining demand charge, and a flat energy charge. The

Staff proposed rate for the small commercial class tracks very closely Public Service's filed C rate, but is slightly lower at lower usage levels and slightly higher at usage levels above 1,700 kilowatt hours. The Staff proposed this rate so as to provide the Commission with the option of maintaining consistency between the general residential and small commercial classes. The Staff proposed rate for small commercial classes likewise maintains consistency with the AED allocation method.

Public Service maintains that Staff is inconsistent in stating that its two-part rate would promote conservation, while at the same time opposing Public Service's five percent conservation assumption. It is true the Staff did oppose the Public Service's five percent conservation erosion adjustment on the basis that the Public Service five percent conservation assumption is not supported by studies, reports, or analyses. The Staff also maintains that in the event the five percent conservation assumption were to be built into the residential rates and conservation did not occur, Public Service would substantially over-recover revenues from the residential and small commercial classes. Moreover, it should be understood that while conservation on the part of Public Service's customers may affect revenues, it is to be expected that it will also have an effect upon costs. It appears to the Commission that Public Service's five percent conservation assumption erosion figure was "pulled out of a hat" without any supporting analyses or studies. We find that Public Service's offer of an after the fact audit to determine whether or not it earned in excess of its authorized rate of return is not appropriate or feasible. Public Service may not earn its authorized rate of return for reasons totally unconnected with so-called conservation erosion. Until more solid data is available the Commission is unwilling to adopt a five percent "guesstimate" of conservation-related erosion stemming from the Staff proposed two-part rate. We find that the Staff proposed two-part rate represents a fair consideration of cost-tracking parameters, rate impact on low usage customers, revenue impact considerations on the Company, and possible conservation features. It is, of course, true that no one, neither the Company, the Commission, nor any intervenor, can predict with mathematical precision what a particularly designed rate will do in terms of its revenue and other impacts upon the utility involved. However, the Commission must use its best judgment, based upon the presentations made to it, of what particular rate design fairly meets the prospective needs of the Company and its customers. We find that the Staff proposed two-part rates for residential and small commercial customers, respectively, are just and reasonable, and should be adopted.

VI. TIME DIFFERENTIATED RATES

A. Time of Day Rates

On November 9, 1978, former President Carter signed into law five separate Acts which collectively came to be known as the "National Energy Act".*

In general, Title I of PURPA requires state regulatory bodies, such as this Commission, and non-regulated utilities to hold evidentiary hearings to "consider" and "make a determination" whether certain rate standards set forth in PURPA are "appropriate" to be implemented in the state and to adopt certain other policy standards unless precluded by state law.

Section 111(d) of PURPA sets forth the rate making standards which must be considered by the Commission including (1) cost of service, (2) declining block rates, (3) time of day (TOD) rates, ** (4) seasonal rates, (5) interruptible rates, (6) load management techniques.

Within two years after the enactment of PURPA, this Commission is required to begin consideration of the six rate standards as set forth in §111(d). A Commission decision that any and all such standards are or are not "appropriate" to carry out the purposes of Title I must be made within three years after enactment of PURPA; that is, by November 9, 1981. Section 113(b) requires that Commission consideration

---

*The five Acts are: (1) The Public Utility Regulatory Policies Act of 1978 (PURPA), Public Law 95-617; 92 stat. 3117; USC 2601, et seq.; (2) the Energy Tax Act of 1978, Public Law 95-618; (3) the National Energy Conservation Policy Act, Public Law 95-619; (4) the Power Plant and Industrial Fuel Use Act of 1978, Public Law 95-620; (5) the Natural Gas Policy Act of 1978, Public Law 95-621.

** Occasionally, the term "time of use" (TOU) is used interchangeably with TOD. TOU, techically, is a broader term which can include rates differentiated by different seasons of the year as well as time of day. When rates are seasonally differentiated, we use the term "seasonal rates."

be made after public notice and hearing, and that the determination of the appropriateness of those standards be made in writing, based upon findings included in such determination and upon the evidence presented at the hearing, and be available to the public.

Fortunately, PURPA provides in §124, that proceedings commenced by a regulatory agency prior to the date of the enactment of PURPA shall be treated as complying therewith "if such proceedings and actions substantially conform" to the requirements of the Act. Section 124 of PURPA provides that any proceeding commenced before the date of enactment of the Act, but not completed before such date, shall comply with the requirements of the Act, "to the maximum extent practicable, with respect to so much of such proceeding or action as takes place after such date."

On July 27, 1979, the Commission issued its initial decision in Case No. 5693, In the Matter of the Generic Hearings Concerning the Rate Structure of All Electric Utilities Operating under the Jurisdiction of the Public Utilities Commission of the State of Colorado, generally known as the "Generic Decision".*

---

*In response to Decision No. C79-1111, various parties filed applications for rehearing, reargument or reconsideration, pursuant to 40-6-114, CRS 1973. On March 6, 1980, the Commission entered Decision No. C80-413 in which it amended Decision No. C79-1111. In Decision No. C80-413, the Commission also granted rehearing with respect to three separate issues, namely (1) power pooling, (2) all issues relating to specific preferential rights and specific provisions of loans under the Rural Electrification Act of 1936, as amended, 7 USC 901, et seq., that would be affected by the promotion of interconnection and coordination of operations by rural electric cooperatives and non-Act electric utilities within and without the State of Colorado, and (3) all issues relating to whether Appendix B to Decision No. C79-1111 should be amended to require Public Service to file interruptible rate schedules applicable to its irrigation customers. On November 18 and 20, 1980, the Commission conducted rehearing in Case No. 5693. On July 7, 1981, the Commission entered Decision No. C81-1198 and entered its order on rehearing with respect to the foregoing issues. Technically, at this time, the so-called Generic Decision is not administratively final.

Although the Generic Decision of the Commission is not administratively final, the Commission in its Decision No. C79-1111 discussed TOD rates and basically concluded that the record in the generic proceeding established a prima facie case in favor of TOD rates for Colorado. In the Generic Decision, the Commission stated that for the vast majority of industrial and large commercial customers, metering costs are not an impediment to the implementation of time of use rates inasmuch as many of the customers in such classes already had meters in place which are suitable for measuring usage by time of day. The Commission further stated that any additional investment required for customers without appropriate meters would be minimal when compared with the potential benefits that could be realized from implementation of TOD rates for those classes of customers. At the same time, the Commission stated that it was convinced of the necessity of moving cautiously with any plan of implementing time of day rates so as to monitor both the customer reaction and the effect upon the utility system. The Commission stated that the numerous characteristics of the industrial and large commercial classes (in addition to low metering cost) justified the implementation of time of day rates for those groups of customers. The Commission further stated, however, that the mere fact that the record in the generic proceeding demonstrated that marginal and average costs of providing power varied with time did not, on its face, dictate wholesale implementation of time of use or time of day rates in Colorado. The Commission signified its intention of evaluating on a case by case basis the cost of implementation of such rates against the likely benefits to be derived therefrom.

Although Public Service may not be conceptually opposed to TOD rates as such, both in Case No. 5693 (the generic proceeding) and Investigation and Suspension Docket No. 1425, Public Service opposed the implementation of TOD rates insofar as Public Service was concerned. Nevertheless, Public Service filed mandatory TOD rates for industrial customers with an annual demand in excess of 500 kilowatts. This filing is responsive to Commission Decision No. C79-1111, page 154, even though, technically, the Commission's Generic Decision is not yet administratively final.

Public Service believes that the benefits to be derived from imposing TOD rates on its system are exceeded by the disadvantages which will result. Public Service believes that its present load shape very nearly reflects the goals which the Commission wishes to achieve and that any further improvement can be attained by rate design techniques such as curtailable air conditioning rates; interruptible rates;* separation of demand and energy charges, especially in the commercial and industrial sector; use of the ratchet; and the residential demand rate for space heating. Public Service believes that the foregoing techniques are significant incentive for customers to control and minimize their loads at all hours of the day.

However, in order to insure that the availability of interruptible rates benefits the entire body of ratepayers, and not solely interruptible customers, for purposes of future system planning, Public Service should not include in its demand forecasts interruptible customers. Although "continuous" interruption of interruptible customers for the sake of interruption is not appropriate, a "paper interruptible rate" (where the customer is an interruptible customer, for all practical purposes, in name only) likewise is inappropriate. The purpose of an interruptible rate is to shave what otherwise would be higher firm demand, thereby reducing the need for additional plant. Shaving load benefits the entire body of ratepayers.

Public Service also believes that there may be a problem from the perspective of the customer who invests substantial sums to purchase equipment necessary to respond to TOD rates only to find that they may later be discontinued as of no value, or worse, detrimental to the system. The Company also posits the possiblity of a sufficient shift from off-peak to on-peak use that additional generating capacity is required to allow the Company to meet its maintenance requirements. In either event, Public Service maintains the end result is higher cost for a utility whose present load system shape already is near optimal.

Public Service indicates that it supports the cost tracking principle as the basis for TOD rates. However, Public Service maintains that in light of what it believes to be a small demand and energy differential warranted on its system, precise cost tracking is not necessary and any minimum benefits are far outweighed by adverse consequences.

No substantial evidence was adduced in this docket which would justify a conclusion by the Commission that the system characteristics of Public Service substantially have changed since Decision No. C79-1111 was issued approximately two years ago. We recognize, of course, that Public Service has a favorable load curve. We further recognize that other rate design techniques, which are mentioned above, also have the potential for conservation, thus retarding system load growth. These recognitions, however, do not detract from our view, already reached in the Generic Decision, that it is appropriate to implement TOD rates in conjunction with these other rate design techniques in an effort to retard future load and peak load growth in Colorado. We also adhere to the conceptual judgment made two years ago in the Generic Decision, that implementation of TOD rates must proceed on a cautious basis. Accordingly, we find that the proposal advanced by AMAX in this proceeding, namely that TOD rates initially should be implemented only with respect to the 32 largest customers of the Company whose current annual usage exceeds 4 megawatts is reasonable and should be adopted. AMAX witness Michael pointed out that Public Service had not performed any empirical load studies with respect to a TOD rate class with loads in excess of 500 kw and this lack has produced substantial difficulty in attempting to arrive at any reasonable estimate of the impact of TOD rates. Accordingly, we accept the AMAX "32 large customer/4 megawatt" alternative as the initial targeted group for whom time of day rates should be implemented. In this way the Commission will be in a better position to monitor and observe the impact of TOD rates on the Public Service system, and this alternative is more in line with the "phased" approach which the Commission believes is the proper way to implement TOD rates in Colorado.

The 4 mw group represents approximately 50% of the demand and approximately 57% of the energy consumed by the so-called 500 kw group.

B. Time of Day Periods

Inasmuch as we believe that the phased implementation of TOD rates in Colorado is likely to result in load shifting from on-peak to off-peak, and also curtail future load, it is necessary to (1) select the number and duration of the time periods during which higher rates will be in effect during the day (2) determine the differential in rates between peak periods and one or more other periods of the day and (3) determine whether the time differentiated periods should be further differentiated by one or more seasons of the year.

Rating period recommendations were made by Public Service, the Staff of the Commission and AMAX. These rating period recommendations are set forth in tabular form in Appendix B to the decision herein. CF&I endorsed the rating period recommendations of Public Service except that CF&I stated that it was appropriate and necessary to extend the on-peak period proposed by Public Service (8 a.m. - 11 p.m.) by one hour to include the hour of 7 a.m. to 8 a.m. Accordingly, CF&I would advocate a peak period from 7 a.m to 11 p.m. on weekdays with the off-peak hours being from 11 p.m. to 7 a.m. on weekdays, and all hours on weekends and holidays.

Although Public Service is not in favor of TOD rates with respect to its own system, it did submit a TOD rate applicable to all customers (secondary, primary and transmission) whose demands are 500 kw or greater. Public Service defined on-peak hours as those occurring between 8 a.m. and 11 p.m. Monday through Friday throughout the year, and off-peak hours as all the remaining hours of the weekdays as well as all hours on weekends and holidays. The hours categorized by Public Service as on-peak and off-peak were determined as a matter of judgment based upon relative loss of load probabilities (LOLP), the system load shape, and the net effective capability of the Company's base load units.

Both Staff witness Parkins and AMAX witness Michael criticized Public Services's failure to include firm purchased power which Public Service is obtaining now and anticipates obtaining in the future in determining its rating periods. Dr. Parkins and Mr. Michael testified that firm purchased power entitlements should be added to the available base load generation, the result of which would be significantly to modify the intersection points of the base load generation and system load curves and thereby produce significantly different daily rating period recommendations.

Staff witness Parkins arrived at his recommended rating peak period essentially by adding the firm purchased power available to Public Service base load generation to determine the intersections with the system load curves as set forth in graph form on Exhibit II-4. As can be seen from Appendix B, the Staff recommendations with respect to the daily rating periods are very similar to the recommendation sponsored by AMAX witness Michael for the summer and winter rating periods. AMAX witness Michael performed a rather comprehensive analysis of the variations in cost and risk in arriving at his recommended rating periods. His analysis was designed to group together homogeneous periods of similar cost and risk and to apply statistical techniques in the refinement and analysis of the
data which he studied. Mr. Michael's use of LOLP as one method in arriving at his recommended seasonal and daily rating periods is

consistent with the preference previously stated by the Commission for use of this method in selecting rating periods. (Cf., Case No. 5693, Decision No. C79-1111, page 187).

Appendix B reveals that both the Staff and AMAX proposed off-peak hours that are close to the off-peak hours proposed by Public Service. However, the chief difference between the Staff and AMAX, on the one hand, and Public Service, on the other hand, is that the Staff and AMAX proposed the use of "shoulder peak" hours while Public Service did not. In the Commission's Generic Decision (No. C79-1111, p.187), we suggested the use of shoulder rating periods during both summer and winter derived by use of the visual inspection method. In our Generic Decision (p. 186), we expressed a preference for three daily rating periods so that costs, and corresponding rates, in the peak period and the intermediate (shoulder) period would be such as to encourage some movement off-peak while encouraging energy conservation. The preference which we expressed in our Generic Decision for three time of day rating periods was not diminished by any of the evidence introduced in Phase II in this docket. We find that three rating periods, consisting of shoulder, peak and off-peak periods, respectively, track costs more accurately than two rating periods and thus should be implemented in this proceeding.

As will be seen from an examination of Appendix B, Public Service did not advocate any seasonal differentiation for time of day rates; AMAX proposed a summer and winter differentiation, and the Staff proposed a summer, winter, and transitional months differentiation. We recognize that the use of transition months for designating rating periods likely tracks costs more precisely than does the development of rating periods that do not acknowledge both the existence of such transition months and the requirement of scheduled maintenance during those months. Nevertheless, the use of transition months with cost differentials and time of day rating periods that vary from those established for summer and winter seasons does conflict with another regulatory goal, namely, that time of day rates should be simple and easily understandable. Staff witness Dr. Parkins, acknowledged that the use of three time of day periods coupled with three seasonal periods (winter, summer, and transition) would involve quite a number of changes throughout the year and in his judgment, the transition months could be done away with in the interest of simplicity.

In our judgment, we believe that two seasonal rating periods per year, coupled with three daily time periods, represents a balanced consideration of both the cost tracking characteristics of the Company's load curve and the desire for reasonable simplicity and understanding. It must be recognized that the selection of rating periods is not an exact mathematical science, but involves the exercise of considered judgment by the Commission. For the seasonal periods, we believe that the winter period should be October 15 through April 14, and that the summer period should be April 15 through October 14. The daily rating periods should be as follows:

<u>Summer</u> (April 15 through October 14)

<u>Peak Hrs</u>:	11 a.m. - 6 p.m. weekdays
<u>Shoulder Peak Hrs</u>:	8 a.m. - 11 a.m. and 6 p.m. - 10 p.m. weekdays
<u>Off Peak Hrs</u>:	10 p.m. - 8 a.m. weekdays and all hours on weekends and holidays

<u>Winter</u> (October 15 through April 14)

<u>Peak Hrs</u>:	4 p.m. - 10 p.m. weekdays
<u>Shoulder Peak Hrs</u>:	8 a.m. - 4 p.m. weekdays
<u>Off Peak Hrs</u>:	10 p.m. - 8 a.m. weekdays and all hours on weekends and holidays

C. <u>Differentials</u>

Public Service has proposed a demand-cost differential of 1.15 between peak and off peak and an energy cost differential of 1.25 between peak and off peak. The demand differential proposed by Public

Service equals the the ratio of all embedded investment to investment in base load generating capacity. The energy differential essentially equals the
ratio of operation and maintenance expenses associated with all generation capacity to the operation and maintenance expenses associated with base load generation capacity.

Both Public Service and the Staff used a variation of the "base-intermediate peak" ("BIP") method for determining the peak/ off-peak demand differential. However, Public Service included $337,124,047 of investments in the Pawnee Unit 1 and $6,656,431 investment in the "Southeast" plant in the formula for calculating the differential. However we find that since Pawnee is not in commercial operation at this time, and the Southeast plant has been indefinitely delayed, neither of these figures should be used in computing the differential. However we will allow the inclusion of that portion of the Pawnee Plant which we allowed to be earned on in Phase I of this docket. That amount, net of FERC, is $120,036,868.

Exhibit II-49 sets forth a summary of rating period demand differentials. Case No. 2 in Exhibit II-49 sets forth the Staff's proposed formula for two seasons and three rating periods which are based upon the exclusion of the Southeast and the inclusion of "Phase I Pawnee."

The foregoing differentials also assume that the annual carrying charge is 25% and the firm purchased power cost is $69,500,000. We agree that the Staff formulae are reasonable. However, we find that the correct annual carrying charge is 15% rather than 25%, as per Public Service's unchallenged rebuttal testimony. The firm purchased power cost was derived by the Staff from the 1980 Annual Report of the Company, and although the calendar year 1980 figure may not coincide with a test year ending June 30, 1980 figure (which was not supplied for the record by Public Service), we find the use of the calendar year 1980 figure of $69,500,000 for firm puchased power is a reasonable proxy. Using the above-described staff formula (with a 15% annual carrying charge rather than 25%) the resultant differentials are as follows:

Peak/Off Peak	=	1.26
Shoulder/Off Peak	=	1.08
Peak/Shoulder	=	1.17

We find that the foregoing demand differentials with a summer season and a winter season, each with three time of day rating periods as more particularly described above, excluding Southeast but including the Phase I Pawnee investment, and using a 15% carrying charge represents a fair and equitable allocation of base, intermediate and peaking plant to the various rating periods.

With regard to the energy differential, Public Service based its energy differential on a formula in which all operation and maintenance expense associated with base load plant was included both in the numerator and denominator. AMAX asserted that energy differentials should be based upon hourly system lambdas for the period of 1981 through 1989. (System lambda is the operating cost of the last generating unit placed on line to meet a system load. Accordingly, system lambda essentially translates into a short-run marginal cost analysis.) By way of contrast the Staff based its proposed energy cost differentials, also using production operation and maintenance expense, on the following formula:

$$\text{Energy Cost differential Shoulder/off peak} = \frac{(1/3 \text{ base} + 1/2 \text{ intermediate})}{1/3 \text{ base}}$$

$$\text{Energy cost differential Peak/off peak} = \frac{(1/3 \text{ base} + 1/2 \text{ intermediate} + \text{peaking})}{1/3 \text{ base}}$$

These formulae and the financial figures supplied by Public Service, yielded a peak/off peak energy cost differential of 1.84 and a shoulder/off peak energy cost differential of 1.33. We find that these energy cost differentials, as calculated by the Staff, are just and reasonable and should be adopted herein.

D. Five Percent Elasticity Adjustment

Public Service has proposed a five percent elasticity adjustment for the TOD rate classes. The five percent elasticity adjustment proposed by Public Service is based upon the judgment of the Company rather than upon any empirical load studies with respect to any Public Service targeted TOD rate class. An effect of this proposed adjustment may very well be to produce a test year over-recovery of the revenue requirement in the event that the targeted TOD rate class did not achieve a five percent shift in energy and demand consumption.

The only empirical evidence before the Commission in this docket on which to assess the validity of Public Service's judgment with respect to the proposed five percent elasticity adjustment is contained in Exhibit II-37 which is a report prepared by the Pacific Gas and Electric Company for the California Public Utilities Commission involving TOD rates for very large customers. The date of the report is March 31, 1980. It is a study of customer responses to Pacific Gas and Electric TOD rates for industrial customers in California. That study indicated a modest 2.7 percent shift from peak to off peak over a three-year study period. The Pacific Gas and Electric rates included a zero demand charge for off peak use and a higher demand differential than those adopted herein. Both of these features of the Pacific Gas and Electric TOD rates logically could be expected to cause a larger demand shift from peak to off peak than the TOD rates proposed in this docket. Until we have some actual experience with TOD rates in Colorado, we believe that it is premature and speculative to build in a five percent elasticity adjustment at this time.

E. Monitoring

The Commission, by this order, is authorizing TOD rates to be implemented for Public Service's largest customers. As a first step in determining the appropriateness of extending TOD rates to a broader range of customers, the Commission must know the effect of the implementation of the TOD rates authorized in this decision. Accordingly, Public Service will hereinafter be ordered to design an appropriate monitoring program and to submit said program for Commission approval.

VII. OTHER ISSUES

A. RD Heating Rate

As part of its Phase II filing, Public Service filed mandatory demand rates for all electric service. Presumably, Public Service's filing was in response to that portion of the Commission's Generic Decision (Decision No. C79-1111) wherein the Commission stated:

> "The Commission is convinced from the record of this proceeding, that demand-energy rates are appropriate for all electric residential and commercial customers. As mentioned, these rates are both compensatory to the utility and provide the customer with an opportunity to control energy cost through load management. Implementation of such should be mandatory for service to new homes, but only after sufficient information and education as to the effective use of such rate has been provided to consumers, homebuilders, and the public at large, by the involved utility. To effectuate this implementation, the Commission believes that there must be a sufficient lead time, prior to establishment of the rate, so that the new homes to which this rate will apply can be designed by homebuilders to provide maximum opportunity for load management. Accordingly, each jurisdictional utility providing all-electric service shall file demand-energy rates for all new residential and commercial customers within six months subsequent to the effective date of this Decision, to be effective 18 months after filing thereof. All affected utilities should note that the Commission is of the opinion that it is appropriate to design demand-energy rates as was done by Public Service Company, so that all-electric customers with a load factor greater than that built into the

current rate schedules will be able to achieve savings." (Commission Decision No. C79-1111, page 147).

Subsequent to Commission Decision No. C79-1111 the Commission granted reconsideration based upon timely petitions filed by a number of parties in that proceeding, including Public Service and the Home Builders Association. On March 6, 1980, the Commission issued Decision No. C80-413 upon rehearing and reconsideration. As relates to demand-energy rates, the Commission amended its prior decision so that the fifth sentence appearing on page 147 of Decision No. C79-1111 would be amended to read as follows:

> "Accordingly, each electric utility, except Public Service Company of Colorado, and each rural electric cooperative providing all-electric service shall file demand-energy rate schedules for all new residential and commercial customers within 24 months after the effective date of this decision. Public Service Company shall file such revised rate schedules, if possible, at its next general rate proceeding, but in no event later than 9 months after the effective date hereof." (Commission Decision No. C80-413, page 22).

The Home Builders Association of Metropolitan Denver states that at the present time, Case No. 5693 is still pending before the Commission for consideration in that no final decision has been rendered therein. Thus, the Home Builders Association argues, the time for filing mandatory demand-energy rate schedules for all new residential and commercial customers has not begun to run and the directive to Public Service to file "as soon as possible", is not yet an effective order. Accordingly, the Home Builders Association has requested the Commission to reject, in this docket, Public Service's proposed tariff sheet R-42, P.U.C. No. 6, which provides for the mandatory demand-energy rates for all new residential customers with electric heating as the principal source of heat or as the primary back up source of heat where other forms of heat are to be used as the principal source of heat. In effect, the Home Builders Association is requesting this Commission to maintain the status quo relative to the demand-energy rates so that the same will remain optional pending a final and effective decision of this Commission in the generic rate proceeding.

We find that the request of Home Builders Association should be rejected. It is true, of course, that the Generic Decision is not technically final. The reason for this is that reconsideration was granted with respect to certain issues therein which did not include the issue of mandatory demand-energy rates of all-electric residential customers. In any event, whether or not the Generic Decision is final is irrelevant. Public Service as an electric utility has the option of initiating new or different rates with respect to any one or more of its classes. If the Commission believes a new rate filed by a utility is reasonable and proper, it need not even suspend the same and set it for hearing, but can allow it to become effective by operation of law. In other words, Public Service has a legal right to propose a mandatory demand-energy rate for all-electric customers with or without the benefit of the Commission's 1979 Generic Decision. We find that the proposed RD rate is just and reasonable and should be allowed to become effective in this docket.

Nothing has transpired since 1979, when the Commission entered its initial Generic Decision, which would lead us to change our mind in this regard. Inasmuch as the Home Builders Association received in early February of 1981 a copy of Public Service's Phase II filing, which clearly indicated that the RD rate was proposed to become effective on a mandatory bases for new all-electric customers, and inasmuch as the Home Builders Association did not choose to enter any evidence in Phase II of this docket as to why the RD rate should not be allowed to become effective in this docket, we find that the Home Builders' request to delete the mandatory RD rate for all-electric customers should be denied.

B. Continuation of General Services Administration Special Contract

At the present time two federal government entities, namely, the Denver Federal Center and Rocky Flats, receive service pursuant to special contracts with Public Service. Public Service has proposed in Phase II of this docket to terminate the special contracts with the Denver Federal Center and Rocky Flats and include the same as members of a new transmission time of day (TT) class. The GSA, on behalf of the Denver Federal Center and Rocky Flats, maintains that both the Denver Federal Center and Rocky Flats have unique load and cost characteristics in that they are transmission, high load factor customers, which own, operate and maintain their own substations and distribution facilities. Thus GSA maintains that the Denver Federal Center and Rocky Flats are much more akin to other special contract customers than they are to other TT customers.

Public Service witness Ranniger testified that the two special contract rates, serving the Denver Federal Center and Rocky Flats, have been eliminated since the load characteristics of those two customers fit the new transmission time of day rate applicable to about a dozen customers.

We find that Public Service's proposal to service the Denver Federal Center and Rocky Flats under the new TT rate is just and reasonable. Contrary to GSA's belief, the TT rate does not take into account distribution facilities. On the contrary, demand and energy charges applicable to all TT customers are determined on the basis of deliveries at transmission level voltages. The customer specific charge is designed to reimburse Public Service for all expenses (return, depreciation, other fixed charges and operation and maintenance expenses) incurred in connection with facilities owned by the Company, but used exclusively to serve the individual customers.

The TT class is defined as those customers taking at transmission level voltage whose demands are between 500 and 25,000 kw. Although Rocky Flats has the largest demand of any of these TT customers, that demand is still 35,000 kw less than the 54,000 kw demand imposed by special contract customer Henderson. We find that Public Service did not act arbitrarily or improperly in establishing the parameters of the TT class and in determining that there was no justifiable basis for excluding the Denver Federal Center and Rocky Flats from that class, the criteria of which they satisfy.

GSA argues that Public Service, with Commission approval, can change the special contract rates for the Denver Federal Center and Rocky Flats, but that Public Service cannot terminate the contracts themselves. The contracts were not put into evidence by GSA, so we have no basis to determine from the record whether any provisions, other than rates, are included therein. None are alleged by GSA. If the contracts speck only to rates as a substantive matter, and we have no basis to assume otherwise, then we find that GSA's legal arguments are without merit.

C. Demand Ratchet

Public Service has proposed a seventy-five percent demand ratchet applicable to on-peak demand for the Climax and Henderson classes. At the present time the existing tariff for Climax and Henderson provides for a 25,000 kw monthly minimum demand billing provision, with a further provision that if off-peak demand exceeds on-peak demand by 150%, all demand in excess of 150% is added to the maximum demand for billing demand determination. AMAX witness Michael stated that the proposed demand ratchet should not be adopted for the Henderson and Climax classes because (a) the existing minimum demand provision sufficiently protects Public Service's investment in facilities to serve these classes, (b) the Henderson and Climax rate classes achieve a high annual and daily load factor, and (c) the demand rachet, as proposed, is inconsistent with TOD rates and would produce a disincentive for customers to consider the development of cogeneration facilities.

A demand ratchet, of course, is intended to recover the fixed costs that the utility incurs for providing service to a customer. A particular customer, for example, may have a very high demand during a portion of the year with a very low or nonexistent demand during other portions of the year. The utility, throughout the year, must meet its fixed costs related to the facilities which serve the customer regardless of the customer's usage. If the maximum demand during the year of a particular customer is, for example, 100 kw then a 75% demand ratchet would mean that the customer would pay demand charges throughout the rest of the year for 75 kw per month regardless of whether or not that particular customer, in fact, incurred 75 kw of demand during the particular month. On having a demand ratchet, it is said that a customer will have an incentive to reduce his maximum demand. In other words, in the example, the 100 kw maximum demand customer may attempt to reduce his maximum demand to 90 kw which, in turn, will correspondingly reduce his demand charges throughout the rest of the year. On the other hand, it may well be that the demand ratchet is counterproductive to conservation in the event that a particular customer may believe that inasmuch as he has to pay 75% of the maximum demand each month, whether or not he in fact imposes that magnitude of demand, he might as well take advantage of 75% of his maximum demand inasmuch as he has to pay for it whether it is imposed on the system or not. At the present time there is no clear indication, either way, whether the demand ratchet is conducive to, or counterproductive to, conservation. On the basis of the limited data which is presently available, we believe that the demand ratchet proposed by Public Service for the GLP, LLP, and contract customers is just and reasonable and should be allowed to become effective. At the same time the Commission desires that Public Service closely monitor the operation of the 75% demand ratchet with respect to these customers in order to obtain the data from which it can be ascertained whether the 75% demand ratchet is operating in favor of, or against conservation. The data should be presented by Public Service in its next general rate case.

VIII. CONCLUSION

The Phase II hearings in this docket have been the most comprehensive Company specific hearings ever held by the Commission, to date, dealing with rate design and cost of service issues with respect to Public Service.

The parties are to be commended for their excellent presentations to the Commission and their vigorous advocacies with respect to the issues which have been discussed in this decision. The Commission believes that the decisions and conclusions reached herein represent a valid and reasonable assessment of the various cost of service and rate design issues that have been presented to it. It must be recognized, of course, that cost of service and rate design issues do not admit of black and white, right and wrong, answers. As can be seen from the body of the decision herein, no radically new departures are to be undertaken by virtue of this decision and order.

On the other hand, some changes are to be implemented, the principal one being the phased and cautious introduction of TOD rates with respect to Public Service's largest industrial and commercial customers. A note of caution is necessary at this point. TOD rates are being introduced on a phased, <u>not an experimental</u>, basis. We fully anticipate that as initial TOD rate data become available and its operational characteristics can be analyzed, that TOD rates will be expanded to include more classes of Public Service's customers. The energy challenge, though perhaps not as psychologically acute as it was several years ago, is not over. New solutions to new problems must be found. We anticipate that the introduction of TOD rates in Colorado will also have a salutary effect with respect to the conservation of energy and capital.

It should be recognized that with respect to cost of service issues, the Commission is not, and cannot be, irrevocably wed to any particular methodology or methodologies. The ones that have been approved and adopted herein seem to us to represent the most balanced and reasonable approaches with regard to Public Service at this same. They may be continued in the future; on the other hand, they may be changed. It will depend upon the facts that are placed before the Commission in future proceedings.

To the extent that specific issues have been raised by the parties which are not addressed specifically in this decision, the Commission states and finds that the particular treatment advanced with respect thereto by one or more of the parties does not merit adoption by the Commission in this docket.

O R D E R

THE COMMISSION ORDERS THAT:

1. Public Service Company of Colorado shall file appropriate tariff sheets to reflect and implement the cost of service and rate design principles set forth in this decision at the revenue level found in Phase I of this docket for the gas, electric, and steam departments, respectively. Said tariffs shall be filed with the Commission on or before September 1, 1981 and shall set forth an effective date therein no earlier than thirty (30) days subsequent to the filing thereof. Said tariffs shall make reference to the decision number herein. Any one or more of said tariff sheets shall be subject to the further order of the Commission.

2. The tariff riders filed by Public Service Company of Colorado pursuant to ordering paragraphs 4, 5 and 6 of Decision No. C80-1039, dated May 27, 1980, shall be continued in effect until the effective date of the tariffs filed pursuant to ordering paragraph 1 herein, subject however to further order of the Commission.

3. The tariff riders filed by Public Service Company of Colorado pursuant to ordering paragraphs 4, 5 and 6 of Decision No. C80-2346, dated December 12, 1980, shall be continued in effect until the effective date of the tariffs sheets filed pursuant to ordering paragraph 1 herein, subject, however, to further order of the Commission.

4. Public Service shall design an appropriate monitoring program to determine the effects of the TOD rates to be implemented as a result of this order and submit said program to the Commission for approval by September 30, 1981.

5. Ordering Paragraphs 1, 2, and 3 of the decision and order herein shall be considered a final decision subject to the procedural provisions of 40-6-114 and 40-6-115, C.R.S. 1973.

6. Motions, if any, relating to attorneys' and witness fees shall be filed with complete time and charges documentation and justifications therefor, on or before September 1, 1981. Said motions will be subject to such disposition as the Commission subsequently may order.

7. This Order shall be effective on August 19, 1981, unless stayed by applicable law.

DONE IN OPEN MEETING the 21st day of July, 1981.

(S E A L)

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

EDYTHE S. MILLER

DANIEL E. MUSE

L. DUANE WOODARD

Commissioners

ATTEST: A TRUE COPY

Harry A. Galligan, Jr.
Executive Secretary

jkm:I&S 1425 Phase II/B

APPENDIX A
Decision No. C81-1282
July 21, 1981

E X H I B I T S

I&S 1425
Phase II

Exhibit	Title and Description
Public Witness II-1	Letter to PUC from Gates Rubber Co w/graphs (5 pages)
Public Witness II-2	Analysis of Proposed Electric Utility Rates, Flack & Kurtz Consulting Engineers
II-A	Direct Testimony of J. D. Heckendorn
II-B	Direct Testimony of J. H. Ranniger
II-C	Direct Testimony of Bruce S. Mitchell
II-D	Direct Testimony of Ernest Tronco
II-E	Direct Testimony of George Parkins
II-F	Direct Testimony of Jan W. Michael
II-G	Direct Testimony of Eugene P. Coyle
II-H	Rebuttal Testimony of Eugene P. Coyle
II-I	Direct Testimony of C. E. Chick
II-J	Direct Testimony of Joseph A. Herz
II-K	Direct Testimony of Harbans S. Chhabra
II-L	Direct Testimony of John A. Bassano, Jr.
II-M	Direct Testimony of Michael J. Ileo
II-1	PSCo. Load Research Survey Progress Report, 1-1-81 (1 page)
II-2	PSCo. Sample Survey Underground Residential Heating Customer Information (216 pages)
II-3	Electric Dept. Average and Excess Demand Customer Information (1 page)
II-4	Relative LOLP and System Load (4 pages)
II-5	Gas Dept. Customer Information (1 page)
II-6	PSCo. Electric Tariff (JHR II-6)
II-7	PSCo. Gas Tariff (JHR II-7)
II-8	PSCo. Steam Tariff (JHR II-8)
II-9	PSCo. Electric Dept. Required Percent Increases at 10.19% Rate of Return (1 page)
II-10	Various Demand Allocation Methods (3 pages)

E X H I B I T S

I&S 1425
Phase II

Exhibit	Title and Description
II-11	Electric Cost of Service Allocation (9 pages)
II-12	Allocation by Average and Excess Demand Method (2 pages)
II-13	Electric Dept. Determination of Average and Excess Demand (13 pages)
II-14	Electric Average and Excess Demand Proposed Increases and Rates of Return (1 page)
II-15	Electric Rate Structure (9 pages)
II-16	Load Research R Data (3 pages)
II-17	Comparison of Monthly Demand Charges (2 pages)
II-18	Electric Dept. Spread Sheets (2 pages)
II-19	Gross Distribution Plant Allocations (15 pages)
II-20	Gas Cost of Service Narrative (8 pages)
II-21	Gas - Proposed Increases and Rates of Return (1 page)
II-22	Gas Dept. Spread Sheets (4 pages)
II-23	Steam Dept. Spread Sheet (1 page)
II-24	Demand and Energy Data - Total Residential General 12 months ending 6-30-80 (1 page) WITHDRAWN
II-25	PSCo. Summary of Load Research Date R-1 Load Factor by Strata (1 page)
II-26	Load Research R. Survey - Individual Peak KW (1 page)
II-27	Customers and Sales Report Total PSCo. (Company Confidential) as of 12-16-80
II-28	PSCo. Comparison of Alternate #1 and Filed R (5 pages)
II-29	Derivation of Demand Blocking PSCo. Filed Residential Rate (1 page)
II-30	Existing R and UR Rate Schedules Colo. PUC No. 5-Electric, Eleventh Revised Sheets No. 101 and 104 (1 page)
II-31	Residential Bill at Different Usage Levels (1 page)
II-32	Commercial Bill at Different Usage Levels (1 page)
II-33	Excerpt from Transcript I&S 1330, 12-19-79, Vol. II pages 312-315

E X H I B I T S

I&S 1425
Phase II

Exhibit	Title and Description
II-34	Excerpt from Transcript I&S 1330 pages 166. 167
II-35	PSCo. Projected Summer and Winter System Peaks 1980 - 1991 (1 page)
II-36	Excerpt from Decision No. C79-1111 Pages 122, 123, 124
II-37	Pacific Gas and Electric Co. Time-of-Use Rates for Very Large Customers - Third Annual Report (79 pages)
II-38	PSCo. Electric Production Plant in Rate Base 6-30-80 12 months ended 6-30-80 (Attachment No. 6) (4 pages)
II-39	PSCo. Electric Demand Cost Determination, 12 months ended 6-30-80 (Attachment No. 13F) (8 pages)
II-40	PSCo. Electric Contribution to System Peak by Rate Class for All Summer and Winter Peaks 1975-1979 (1 page)
II-41	Summer Net Effective Capability (2 pages)
II-42	Load Forecasting and Capacity Planning - National Regulatory Research Institute 1979 - Douglas N. Jones (20 pages)
II-43	Synthetic Load Duration Curve - Graph
II-44	Derivation of the Average and Excess Demand Equation (2 pages)
II-45	Derivation of the Class Allocation Factor (3 pages)
II-46	Graph Showing Cents per Hour (1 page)
II-47	Graph Showing KWH Usage (1 page)
II-48	PSCo. Load Research
II-49	PSCo. Summary of Rating Period Differentials (3 pages)
II-50	PSCo. Total Loss of Load Hours by Month 1980-1989
II-51	Sensitivity Analysis of PSCo. Demand Differential Determination
II-52	Summary Table of Large Commercial and Industrial Time-of-Day Rates (12 pages)
II-53	Hypothetical Ten Percent Shift to On-Peak Demand and Energy to the Off-Peak Period for the Test Year for Climax
II-54	Hypothetical Ten Percent Shift to On-Peak Demand and Energy to the Off-Peak Period for the Test Year for Henderson

E X H I B I T S

I&S 1425
Phase II

E X H I B I T S

I&S 1425
Phase II

Exhibit	Title and Description
II-92	Average Unit Rate in Mills/KWH at Proposed Rates for Rockwell International (Rocky Flats or ERDA)
II-93	Map of Rocky Flats - Area Plot Plan
II-94	Rocky Flats Map - Plant Power Distribution System
II-95	ABEX Corp. Product Directory - U. S. Operations (1 page)
II-96	PSCo. Tariff Sheets Schedule SPP 147, 147a
II-97	PSCo. Tariff Sheets Schedule LLP 143, 143A
II-98	PSCo. Tariff Sheets Schedule PT 65, 65A
II-99	ABEX-Denver-Calculation of Present Power Bill as Reported
II-100	New Proposed Rate - PT Schedule and Sheet No. 65
II-101	Calculation of New Power Bill - New PT Rate with Demand Control and Normal Production
II-102	ABEX Electric Foundries U. S. Electrical Data
II-103	ABEX Annual Power Bills - 1979, 1980, 1981
II-104	ABEX Annual Power Bill - Proposed PT Rates
II-105	Class Contribution to Company Generation Level Peak During Summer 1979 (5 pages)
II-106	Class Contribution to Company Generation Level Peak During Winter 1978-79 (5 pages)
II-107	Development of Proposed R Rate Designs
II-108	Development of Proposed RH and RD Rate Designs
II-109	Schedule R Residential Bill Comparison at Differenct Usage Levels
II-110	Comparison of Monthly Bills for Schedule RH Customers under Company's Prior, Current and Proposed RH and RD Rates and Under Ileo's Proposed RH Rates
II-111	Comparison of Monthly Bill for Schedule RD Customers under Company's Prior, Current and Proposed RD Rates and Under Ileo's Proposed Rates

E X H I B I T S

I&S 1425
Phase II

Exhibit	Title and Description
II-76	Development of Peak and Average Demand (1 page)
II-77	Comparison of Demand Responsibility Under Three Allocation Methods (1 page)
II-78	Cost Based Rates by Medley Palmer
II-79	PSCo. Summary of Transmission Time-of-Day Study Results (4 pages)
II-80	Summary of Transmission "TT" Revenue Requirements by Cost Component Average and Excess Demand Method (14 pages)
II-81	Summary of Transmission "TT" Non-Time of Use Cost of Service Rates Average and Excess Demand Method (3 pages)
II-82	PSCo. Tariff Sheet Transmission Time-of-Day Service Schedule II (3 pages)
II-83	PSCo. Calculation of Time-of-Use Energy Charges and Demand Provision Transmission Time-of-Day Rate "TT" and Schematic System Diagram
II-84	Comparison of Present and Proposed Revenues and Average Unit Rates per Company GSA's Denver Federal Center for 12 Months Ended 6-30-80
II-85	Average Unit Rate in Mills/KWH at Present Rates for GSA's Denver Federal Center
II-86	Average Unit Rate in Mills/KWH at Proposed Rates for GSA's Denver Federal Center
II-87	Map of Denver and Surrounding Area Showing GSA agencies
II-88	Map Showing Electric Distribution for Denver Federal Center
II-89	Letter from PSCo. to GSA Public Utilities Management Division dated March 30, 1979 with attachments
II-90	Comparison of Present and Proposed Revenues and Average Unit Rates Per Company (Rocky Flats or ERDA)
II-91	Average Unit Rate in Mills/KWH at Present Rates for Rocky Flats or ERDA

APPENDIX B
Decision No. C81-1282
July 21, 1981

SUMMARY OF RECOMMENDED RATING PERIODS

Public Service Company Recommended Rating Periods

On-Peak Period - 8:00 A.M. through 11:00 P.M.
Monday through Fridays except when such days are also an excepted holiday. Holidays excepted from on-peak hours would be: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Off-Peak Period - All hours and days, including excepted holidays, which are not specified as on-peak periods.

Staff Recommended Rating Periods

Summer Season - June, July, August

On-Peak Period - 11:00 A.M. - 6:00 P.M. Weekdays

Shoulder Peak Period - 8:00 A.M. - 11:00 A.M. Weekdays
6:00 P.M. - 10:00 P.M. Weekdays

Off-Peak Period - 10:00 P.M. - 8:00 A.M. Weekdays
All hours on weekends and holidays.

Winter Season - November, December, January, February

On-Peak Period - 5:00 P.M. - 10:00 P.M. Weekdays

Shoulder Peak Period - 8:00 A.M. - 5:00 P.M. Weekdays

Off-Peak Period - 10:00 P.M. - 8:00 A.M. Weekdays
All hours on weekends and holidays.

Transition Season - March, April, May, September, October

On-Peak Period - 8:00 A.M. - 10:00 P.M. Weekdays

Off-Peak Period - 10:00 P.M. - 8:00 A.M. Weekdays
All hours on weekends and holidays

AMAX Recommended Rating Periods

Summer Season - May through September

On-Peak Period - 12:00 Noon - 6:00 P.M. Weekdays

Shoulder Peak Period - 8:00 A.M. - 12:00 Noon Weekdays
6:00 P.M. - 10:00 P.M. Weekdays

Off-Peak Period - 10:00 P.M. - 8:00 A.M. Weekdays
All hours on weekends and holidays.

Winter Season - October through April

On-Peak Period - 4:00 P.M. - 10:00 P.M. Weekdays

Shoulder Peak Period - 8:00 A.M. - 4:00 P.M. Weekdays

Off-Peak Period - 10:00 P.M. - 8:00 A.M. Weekdays
All hours on weekends and holidays.

E X H I B I T S

I&S 1425
Phase II

Exhibit	Title and Description
II-112	1979 PSCo. Usage and Demands by Residential Group Consolidated Group R (Per Customer Basis) (3 pages)
II-113	1979 Residential Group Embedded Costs per KWH Using Company Average and Excess Methodology
II-114	1979 Residential Marginal Cost per KWH Using Company Marginal Costing Methodology
II-115	PSCo. Comparison of Residential Electric Heating Rates - URD and URH Including Load Control Option Under the Demand Rate
II-116	Final Order of the Public Utility Commission of Texas in Docket No. 3006 - Application of Texas Power & Light
II-117	Replacement of Page 18 for Coyle Cost of Service #3
II-118	Replacement of Page 29 for Coyle Cost of Service #3
II-119	Coyle's Average & Excess with "Dual Peak" (16 pages)
II-120	Coyle's Narrative to Accompany Exhibit showing results of "Dual Peak"
II-121	Page 18 to Accompany Coyle's method with "Dual Peak"
II-122	Equivalent for "Dual Peak" Version
II-123	Work Paper PSCo. "Dual Peak" in A & E D
II-124	PSCo. Total Company (Unitized) System Peak Day (24 pages)
II-125	PSCo. Demand Charge Differential Based on BIP Method 12 months ended June 30, 1980
II-126	PSCo. Comparison of Residential Heating Individual and Group Demands
II-127	PSCo. Electric Dept. 12 months ended June 1980 Required Percent increases at 10.19% Rate of Return Under Various Demand Allocation Methods (2 pages)
II-128	PSCo. Alternate Demand and Energy Rates for Filed Time-of-Day Rates
II-129	PSCo. Electric Dept. 12 months ended June 1980 Modified Average and Excess Demand - S/W Average Peak - Archibold's Method - Customer Information (14 pages)