(Decision No. C93-1346)

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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RE: THE INVESTIGATION AND SUSPENSION OF TARIFF SHEETS FILED BY PUBLIC SERVICE COMPANY OF COLORADO, ADVICE LETTER NO. 1192-ELECTRIC, ADVICE LETTER NO. 477-GAS, AND ADVICE LETTER NO. 53-STEAM.	)	DOCKET NO. 93S-001EG

COMMISSION ORDER

Mailed Date: October 27, 1993
Adopted Date: October 14, 1993

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BY THE COMMISSION:

{PRIVATE }HISTORY OF PROCEEDINGS{tc \l 1 "HISTORY OF PROCEEDINGS"}

On January 20, 1993, Public Service Company of Colorado ("PSCo" or "Company") filed with the Commission Advice Letters Numbered 1192-Electric, 477-Gas, and 53-Steam. The purpose of these filings was to request the Commission's approval of an increase in the Company's annual electric, gas, and steam revenues of $81,643,000. Advice Letter No. 1192-Electric proposed to place into effect a General Rate Schedule Adjustment rider and a revised Energy Cost Adjustment, both to become effective on February 20, 1993.[1] Pursuant to the new tariffs suggested in Advice Letter No. 1192-Electric, the Company's revenues would increase $47,412,000, which is an overall increase of 4.01 percent in electric rates, based on a 12-month future test year ending June 30, 1994.[2] The

[1] In the January 20, 1993, Advice Letters, the Company also suggested an Earnings and Service Quality Incentive Plan. This plan is PSCo's recommended form of incentive regulation which, if approved, would result in annual prospective rate adjustments based upon the Company's earnings for a prior 12-month period. Under the proposal, the Company and ratepayers would share earnings in excess of the authorized rate of return depending on the amount of overearnings. In Decision No. C93-325, we severed all issues relating to incentive regulation from the present docket and consolidated them in Docket No. 93I-199EG which is known as the Incentives and Decoupling docket.

[2] As discussed, *infra*, PSCo's use of a future test year in its initial filing proved to be one of the most disputed issues in this proceeding.

Company's requested revenue increase was also based upon a 13.0 percent rate of return on equity and a 10.5 percent return on rate base.

Advice Letter No. 477-Gas proposed a revenue increase of $33,698,000, which represented an overall increase in gas rates of 6.09 percent. Like the electric filing, Advice Letter No. 477-Gas was based upon a future test year ending June 30, 1994, an authorized return on equity of 13.0 percent and a 10.5 percent return on rate base. Additionally, the Company's filing reflected the merged gas cost adjustment clause resulting from the merger of PSCo with Western Gas Supply Company, a wholly-owned subsidiary of PSCo. That merger was approved by the Commission and became effective on January 1, 1993. Under the Company's proposal, the requested gas rate increase would apply to sales customers, and to transportation customers only to the extent they take service under the Sales Service portion of the Firm and Interruptible Gas Transportation Service Rate Schedules.

In Advice Letter No. 53-Steam the Company proposed a revenue increase of $533,000, which is an increase of 6.3 percent in rates. Again, this request was based upon a future test year and an authorized rate of return on equity of 13.0 percent, and a 10.5 percent return on rate base.

Like the electric advice letter, the gas and steam advice letters proposed effective dates for the new tariffs of February 20, 1993. In Decision No. C93-144, we suspended the effective dates of the new tariffs for 120 days and set this matter for hearing in accordance with the provisions of section 40-6-111(1), C.R.S. (1993).[3] By Decision No. C93-662, we suspended the proposed tariffs for an additional 90 days as permitted by section 40-6-111(1), C.R.S. (1993), numerous parties intervened. (The parties in this case are listed in Attachment A to this decision.) Originally, hearings in this matter were set to begin on July 6, 1993.[4] However, on June 16, 1993 PSCo filed a Request for Prehearing Conference and for Such Other Relief As May Be Appropriate which, in essence, requested a continuance of the procedural schedule, including the previously set hearing dates. As grounds for its request for continuance, the Company stated that the parties required additional time before hearing to conduct additional settlement negotiations.

In accordance with the Company's request we conducted a prehearing conference on June 22, 1993, and issued as a result

[3] Consistent with prior practice involving PSCo, the present proceeding was limited to revenue requirement issues, or issues concerning the appropriate level of the Company's overall earnings. This proceeding is called "Phase I" of the rate case. Cost allocation and rate design issues will be addressed in future proceedings, which will be called Phase II of the rate case.

[4] In addition to the evidentiary hearings, the Commission set and conducted public witness hearings at a number of locations throughout the State.

thereof Decision No. C93-731. In that decision, we vacated the previously set hearing dates. However, in order to secure its continuance, the Company agreed at the June 22, 1993 prehearing conference to amend the proposed effective dates of all three advice letters.[5] The change in proposed effective dates was important because section 40-6-111(1)(b), C.R.S. (1993), requires the Commission to render a decision on suspended tariff filings within 210 days of the proposed effective date, and because the previously adopted procedural schedule was set, based upon the Company's suggested effective date of February 20, 1993.

The parties were ultimately unable to reach a full settlement in this matter and, in Decision No. C93-826, we issued a new procedural schedule. Hearings were set to begin on August 16, 1993 and to continue on August 17, 18, 20, 23 through 27, and September 13 through 17, 1993. The Commission conducted the hearings in this case on all of the assigned dates.

Pursuant to order of the Commission, the parties prefiled direct, rebuttal, and surrebuttal testimony and exhibits. Except as specified in this decision, all prefiled testimony was offered and received into evidence at hearing, and cross-examination and redirect examination were heard. Exhibits A-Z, AA-PP, RR-SS, UU,

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[5] The Company later formally amended the proposed effective date of the new tariffs to May 4, 1993. Therefore, the 210-day suspension period in this proceeding expires on November 30, 1993.

XX-ZZ, AAA-DDD, 1-5, 8-233, 235-236, 238-252, 254-296, and 299-344 were offered and received into evidence. On September 29, 1993, the parties filed closing statements of position.[6] We conducted open meetings to deliberate and decide this matter on October 8, 13, and 14, 1993. We now issue our written order.

{PRIVATE **}**RULING ON MOTION TO STRIKE**{**tc \l 1 "RULING ON MOTION TO STRIKE"**}**

In its closing Statement of Position, the OCC reasserts the motion to strike certain portions of Mr. Kelly's rebuttal testimony offered on the last day of hearing which it lodged when Mr. Kelly testified. Staff joined the motion at hearing. In its Statement of Position, Staff continued its objection, though not through a formal motion, to the Commission's consideration of some of Mr. Kelly's rebuttal testimony. Specifically, Staff argued that it would be a violation of due process for the Commission to consider Mr. Kelly's testimony regarding the revenue impact of the Commanche baghouse and Exhibit 345, Mr. Darnell's workpaper quantifying the revenue impact of the baghouse. The OCC's formal motion to strike addresses the rebuttal testimony regarding the Commanche baghouse (including Exhibit 345), as well as rebuttal concerning the effect of out-of-period stock issuances on the Company's revenues (including Exhibit 344 which shows the effects

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[6] WestPlains was allowed to file its Statement of Position on September 30, 1993, by order of the Commission herein.

of the new stock issuances on the Company's capital structure).

Staff and the OCC argued that Mr. Kelly's rebuttal was actually an eleventh hour modification to the historical test year. It is their position that the objectionable rebuttal testimony should have been included in the Company's direct case. The two parties then conclude that to allow such a modification of the historical test year and the requested rate relief in rebuttal would constitute a violation of due process. The parties cite *Potomac Electric Power Co. v. Public Service Commission*, 402 A.2d 14 (D.C. App. 1979), in support of this position.

We will deny the motion to strike except as it relates to Exhibit 345. The OCC and Staff have misinterpreted the purpose for which the rebuttal testimony was offered. The purpose was to address the issue regarding whether the Company's earnings were susceptible to attrition--an issue that was the subject of extensive comment in the direct cases of many parties, including Staff, the OCC, and the Company. The testimony was also intended to address the debate regarding whether or not the Company's earnings would be, or should be, sufficient to maintain the dividend in light of anticipated new expenses and at some of the recommended reductions in allowed returns on equity (*e.g.*, the Staff position presented by Mr. Ekland). The rebuttal testimony was not being offered, or accepted, as a specific request for additional revenues which were not part of the historical test year. Therefore, it is inaccurate to characterize the disputed rebuttal as an amendment to the test year. For this reason, the *Potomac Electric* case is clearly inapposite.[7]

We also observe that neither of the two issues commented upon by Mr. Kelly in the disputed rebuttal testimony (*i.e.*, the revenue impact of the Commanche baghouse, and the Company's plans to issue new stock after the rate case) was new to the hearing. Each topic was discussed by various witnesses prior to Mr. Kelly's rebuttal. For example, Mr. Ekland of Staff in his oral testimony generally corroborated Mr. Kelly's quantification of the impact of the Commanche baghouse. Therefore, Mr. Kelly's actual quantification of the revenue impacts of these two items was not so new to the hearing to raise the specter of due process violations. What's more, Mr. Kelly's testimony that the revenue impact of the Commanche baghouse is $4.967 million, should not be stricken inasmuch as the parties did have an opportunity to cross-examine those statements. The testimony was proper rebuttal. The parties could not validly claim surprise.

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[7] That case involved a last-minute, substantial change to the originally filed test year. In particular, the utility in that case, as part of its rebuttal, sought to change <u>the entire</u> test year from year end 1974 to the year ending June 1975. The disputed rebuttal here involves two specific issues, not a wholesale change to the litigated test period. Moreover, we note that the court in that case held that, " . . . a request to use more recent data submitted in a last minute filing . . . is to be resolved in the reasonable exercise of the Commission's discretion." *Potomac Electric*, *supra*, at 19.

We also disagree with the OCC's argument that consideration of the testimony would violate the precepts of *Colorado Municipal League v. Public Utilities Comm*., 687 P.2d 416 (Colo. 1984) (the Commission should not make adjustments to test year factors without considering related adjustments). As discussed above, the testimony was not offered as a request for additional revenues, and the Commission did not consider it as such in this decision. Therefore, consideration of the rebuttal cannot result in a distortion of the test year.

However, we will grant the motion to strike Exhibit 345, which actually was submitted at the request of the Commission through its counsel. We agree that the late-filed exhibit is sufficiently complex, that questions of fairness arise out of the parties' inability to conduct cross-examination on the document.

{PRIVATE **}**APPROVAL OF STIPULATIONS**{**tc \l 1 "APPROVAL OF STIPULATIONS"**}**

Prior to the conclusion of the hearing, some of the parties entered into settlements concerning certain disputed issues in this case. The settling parties offered their written agreements into evidence as Exhibits 250, 251, and 329. The settling parties requested that the Commission approve those stipulations set forth in the agreements as the appropriate resolutions of the disputed matters. With one exception, discussed *infra* , no party objected to the policies set forth in the agreements. For the reasons set forth in this section of the decision, we will approve the stipulations as reasonable dispositions of the parties' contentions.

{PRIVATE **}**Exhibit 250--Plant Held For Future Use and Colorado-Ute Acquisition**{**tc \l 2 "Exhibit 250--Plant Held For Future Use and Colorado-Ute Acquisition"**}**

The first stipulation offered for Commission consideration was Exhibit 250, entered into by the Company, the OCC, and Staff. Exhibit 250 provides:

1. The Plant Held For Future Use ("PHFU") concerning water rights for the Southeast Colorado Steam Plant and other expenses relating to the design of the Pawnee 2 plant shall be included in the Company's rate base for this docket, and shall accrue a return based upon the Company's weighted cost of debt and preferred stock, but shall exclude common equity costs. No amortization of Pawnee 2 costs will be made. In addition, remaining assets identified in the Company's filing as PHFU shall be included in rate base and accrue the authorized return as determined in this case (*i.e.*, based upon the weighted cost of debt, preferred stock, and common equity).

2. The acquisition of assets from the Colorado-Ute Electric Cooperative shall be accounted for in the following manner:

   a. The Company will book a negative acquisition adjustment of $5.9 million, which represents the excess of the net value of the assets obtained by PSCo over the purchase price of those assets. The amortization period will be the remaining life of the associated assets;

   b. The Company will refund to its customers certain coal royalty and purchased power offsets in the amount of $6.7 million through a reduction of the Electric Cost Adjustment ("ECA") over a 12-month period;

c. The Company will not seek recovery from retail customers of the remaining $3.6 million (50 percent) of the purchase price of the Holy Cross distribution assets. Recovery of the other 50 percent of the costs of those assets, as approved in Decision No. C92-1729, shall not be affected by the stipulation; and

d. The Company will not seek recovery from retail customers of the Glenwood Springs portion of the Holy Cross unsecured creditors' payment of approximately $1.6 million.

With respect to PHFU, the Company, in its filing, included certain plant in rate base, even though the plant in question is not being used in the provision of electric service to ratepayers. The Company included $27.898 million in rate base for water rights associated with the Southeast Colorado Steam Plant. That plant is not expected to be constructed and operational until some time after the year 2010. Since this plant is not currently used in the provision of service, the OCC, Intervenor Cities, and Staff objected to its inclusion in rate base. The Company responded that considerable lead-time is necessary to acquire certain assets such as water supplies. According to the Company, if prudent long-range planning is not pursued, ratepayers would be required to pay additional, premium costs to meet compressed and imprudent deadlines.

Similarly, the Company included $18.4 million for engineering and design costs for the planned Pawnee 2 unit. *See* discussion, *infra*. Staff, OCC and Intervenor Cities objected to inclusion of this plant in rate base as well. These expenditures, the objecting parties argued, were not associated with used and useful plant. The Company's argument for inclusion reasoned that ratepayers have benefitted substantially from the Colorado-Ute acquisition (*e.g.*, the Company acquired 333 MW of capacity at approximately $300/kW as compared to a cost for new construction of $1500/kW) which has delayed the necessity to proceed with planned construction of Pawnee 2. The Company now estimates that the plant will not be needed until the year 2011. However, the Company suggests, since the engineering and design costs were prudent at the time they were incurred, the $18.4 million expended should be included in rate base at the present time.

The compromise by the parties allows this PHFU (*i.e.*, Southeast water rights and Pawnee 2 engineering and design costs) into rate base, but at a rate of return which excludes equity costs. In essence, the Company will be allowed to recover its out-of-pocket expenses associated with this PHFU.

A number of witnesses addressed the appropriate adjustments to be made for the Ute acquisition. The historical context for the discussion was described by the testimony. Prior to filing bankruptcy on March 30, 1990, Colorado-Ute was the largest cooperative electric association in the State. It had an interest in approximately 1,082 MW of generating capacity, as well possession of a significant bulk transmission system and related substations, and other assets. Colorado-Ute provided wholesale power to 14 rural electric associations. However, for a variety of reasons, it was unable to pay its debts and ultimately filed for bankruptcy. Eventually, PSCo agreed to purchase a portion of Colorado-Ute's assets.[8] That purchase was approved by the Commission in Decision No. C91-1779, Docket No. 91A-589E.

In Decision No. C91-1779, we ruled that the Company would be permitted to book an adjustment for any difference in the acquisition price and the net book value of the assets purchased from Colorado-Ute. At that time, the Company estimated a positive adjustment of $10 million. However, due to delays in completing the transfer, the Company actually acquired the assets for $5.9 million less than book value. Instead of making a negative $5.9

[8] Other portions of Colorado-Ute assets were purchased by Tri-State Generation and Transmission and PacifiCorp.

million acquisition adjustment in its original filing in this case, the Company sought approval of a positive $11.0 million acquisition adjustment. This amount was derived by including Pawnee 2 engineering costs, *supra*, costs associated with Holy Cross distribution assets,[9] and costs associated with the Glenwood Springs portion of the Holy Cross unsecured creditors payment.[10]

[9] As part of its purchase agreement in the Colorado-Ute bankruptcy proceedings, the Company agreed to purchase certain transmission and distribution facilities owned by Holy Cross Electric Association, one of Colorado-Ute's wholesale customers. In Docket No. 91A-589E, the Commission approved recovery of 50 percent of these costs in rates. The Company now requests recovery of the remaining 50 percent, contending that the purchase of the Holy Cross assets was one component of the Ute acquisition, an acquisition which was, on the whole, of substantial benefit to ratepayers. Intervenors, including Staff, argue that these expenditures do not benefit ratepayers. For example, Intervenors contend that the Company agreed to purchase Holy Cross's facilities as a concession to attract new wholesale customers. (As part of the bankruptcy settlement, PSCo agreed to purchase Holy Cross's facilities, and Holy Cross agreed to become a PSCo wholesale customer.) Intervenors then argue that retail ratepayers should not pay for rate concessions made to wholesale customers.

[10] Another provision of the Colorado-Ute bankruptcy settlement required the Company to contribute $45 million to a fund to compensate Colorado-Ute's unsecured creditors. The Company was to recover this $45 million through surcharges on purchased power costs to be paid by the four new wholesale customers which PSCo acquired from Colorado-Ute. In turn, the customers of the Company's new wholesale customers were to be assessed a surcharge for these costs. Under the bankruptcy agreement, if any of the wholesale customers of the Company's four new wholesale customers begins receiving service directly from PSCo, the amount of the surcharge allocated to that customer is to be forgiven. Glenwood Springs was formerly a wholesale customer of Holy Cross, and it was determined that Glenwood Springs' share of the payment to unsecured creditors was $1.6 million. Glenwood Springs subsequently became a direct wholesale customer of the Company. Consequently, PSCo has lost the surcharge for Glenwood Springs ($1.6 million) that it would have collected from Holy Cross had Glenwood Springs not become a direct customer of PSCo. The Company originally sought to recover this $1.6 million as part of its acquisition adjustment. Intervenors opposed this also on the grounds that this was a concession to attract wholesale customers and should not be passed on to retail ratepayers.

The stipulation between the Company, Staff, and the OCC resolves the Colorado-Ute acquisition adjustment essentially in the manner advocated by Staff and the OCC. Intervenor Cities, through witness Jamshad Madan, suggested in prefiled testimony that neither a gain nor a loss should be recognized on the Ute acquisition. The Cities do not oppose other aspects of the stipulation.

We accept the stipulation as a fair and reasonable resolution of the issues. The manner in which the Ute acquisition is treated in the settlement is consistent with our prior directives in Decision No. C91-1779 that the acquisition adjustment should reflect the actual difference between the acquisition price and net book value of the assets. We also agree with Staff's and the OCC's arguments regarding the appropriate treatment of other components of the Ute acquisition (*i.e.*, coal royalty and purchased power offsets, Holy Cross distribution facilities, and the Glenwood Springs portion of surcharge).

As for inclusion of Southeast water rights and Pawnee 2 costs in rate base, we acknowledge the soundness of the "used and useful" principle as strongly emphasized by the Cities and others. However, we agree with the Company that ratepayers have benefitted from the Pawnee 2 and the Southeast water rights expenditures. We also agree with the Company that, in light of required lead-times for constructing new plant, prudence requires long-term planning. Perhaps, more importantly, ratepayers have received substantial benefit from the Ute acquisition through the Company's acquisition of additional capacity at bargain prices.[11] The Company's actions have also caused delay in construction of other projects such as Pawnee 2, a substantial and direct benefit to its customers. We conclude that, in these circumstances, it would be unfair to penalize the Company by disallowing Pawnee 2 costs for actions which have been of great benefit to ratepayers. The stipulation appropriately recognizes the used and useful principle, as well as the value of the Ute acquisition to customers by allowing the subject expenditures into rate base only at a return based upon debt and preferred stock. This is fair and reasonable to both ratepayers and the Company in light of the facts of this particular case.

{PRIVATE **}**Exhibits 251 and 329--General Accounting Adjustments**{**tc \l 2 "Exhibits 251 and 329--General Accounting Adjustments"**}**

The Company and the OCC entered into a further stipulation to resolve a number of disputes which are explained in the prefiled testimony of the two parties. The stipulated agreements, Exhibits 251 and 329, also make a number of corrections to the Company's *pro forma* test year operating and maintenance expenses. No party

[11] The Company's participation in the Colorado-Ute bankruptcy proceedings was also in the public interest inasmuch as it helped resolve serious questions for the State as to how Ute's former customers would continue to be served.

opposed the agreement, and we now approve them as a reasonable disposition of the disputed matters. Generally, the stipulation sets forth the parties' agreements concerning:

- Allocation of electric administrative and general expenses to the Fort St. Vrain ("FSV") plant;[12]

- FSV operation and maintenance expense exclusion;

- Prepaid pension asset to be recognized in rate base in pretax amounts;

- A *pro forma* adjustment to rate base for annualized lease expenses;

- Deduction of Qualifying Facility deposits and application fees from rate base;

- Deduction of one-half of the Company's pre-1971 accumulated deferred investment tax credits from rate base;

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[12] As stated in the stipulation, the calculation supporting the FSV allocation of administrative and general costs was based upon the OCC's method, but the method was applied to the ratio of FSV employees to total Company employees in 1993. We reluctantly accept this last ratio as a proxy for purposes of the decision. As noted elsewhere, with a more updated test year, there would be no need for ratio-type allocations of this sort.

- Modification to the lag in payment of vacation pay;

- Exclusion of lag in payment of interest and preferred stock dividends from cash working capital allowance;

- Modification of merit increase expenses in test year;

- Adjustment for recovery of gas shrinkage expense and liquids revenue in base rates;

- Miscellaneous corrections to the Company's test year operating and maintenance expenses.

As stated above, the reasons for the particular treatment agreed to in the stipulations were presented in the parties' prefiled testimony. No dispute now exists between any of the parties on any of these issues. We now find that the agreements are fair and reasonable and should be approved in light of the particular facts of this case.

{PRIVATE **}**INTRODUCTION OF TEST YEAR**{**tc \l 1 "INTRODUCTION OF TEST YEAR"**}**

A test year is a 12-month period of time in which the interrelationships of revenue, expense, and investment are evaluated and adjusted, and then it becomes a model by which to set new rates. The purpose of a test year is to provide, as closely as possible, an interrelated picture of revenue, expense, and investment reasonably representative of the interrelationships that will be in place at the time the new rates proposed in a rate case will be in effect.

Notably, a test year is defined by the interaction of its component parts; no single component stands alone. Built into the test year are input and output quantities for the designated period and how they affect or are affected by the operations of the utility (*i.e.*, matching). To be sure, the absolute quantities of input and output, and certainly prices, will change when the test year has ended and the new rate year arrives, but the key to test year integrity is the interrelationship of these items, not the individual dollar quantities designated for each.

The historic test year adopted by the Commission in this case is constructed as follows: Historic, book numbers are adjusted by removing items which are recorded in the test year, but which apply to previous periods, including items applicable to the test year that were not recorded in the test year, and reclassification of items between and among departments, etc. After these accounting adjustments are made, "Commission" adjustments, such as disallowances for certain expenses, are made. Then, *pro forma* adjustments are made to the test year. These adjustments largely consist of annualization of price changes that occurred within the test year (in-period adjustments) or outside the test year (out-of-period adjustments). According to prior Commission policy, the cutoff period for inclusion of out-of-period adjustments is one year after the test year ends, not one year after the rates go into effect as was claimed by some of the parties. A one-year cutoff permits adjustments outside the test year, but does not distort the matching and interrelationships of the test year components. If a number of adjustments proposed are from outside the cutoff period and the magnitude of the proposed adjustments is significant, it may well indicate that the proposed test year is insufficient and should be updated with a later test year.

{PRIVATE **}**FORECASTING AND THE FUTURE TEST YEAR**{**tc \l 1 "FORECASTING AND THE FUTURE TEST YEAR"**}**

<u>**{**PRIVATE **}**Public Service Company**{**tc \l 2 "Public Service Company"**}**</u>

Several PSCo witnesses, principally Earl E. McLaughlin, W. Wayne Brown, and James F. Gilliam, and Melvin Dick from Arthur Andersen and Company, filed direct testimony concerning the process used by PSCo to develop its forecasts, as well as the future test year resulting from it. This direct testimony was offered to support the Company's additional revenue request for $81.6 million, based upon a fully forecasted test year beginning

July 1, 1993, and ending June 30, 1994.

PSCo argued that its reliance on a future test year was necessitated, in part, by the changes occurring in its industry. The Company alluded to changes occurring in energy technology and regulation, as well as mergers and acquisitions which have introduced never-before-encountered complexities and uncertainties into the energy services industry. According to the Company, customers now have more options available to them to meet their energy needs than ever before, and some of these options do not include PSCo. Large customers, in particular, can engage in self-generation of electricity, gas bypass, fuel switching, relocation outside PSCo's service territory, or discontinuation of business. To the extent the Company loses some of these customers, its fixed costs will need to be spread over a smaller customer base, resulting in higher rates for those remaining customers. The Company contended that it must take these competitive forces into account in its pricing, quality, and service-offering decisions. Additionally, the Company maintained that it must use a future test year in ratemaking proceedings.

A future test year is forward-looking and allows the Company to set rates based upon its anticipation of the changes which are occurring, or are about to occur. According to the Company, it should not be burdened by an historic test year which cannot be representative of the future years in which the new rates will actually be in effect. In the Company's view, even *pro forma* adjustments cannot adequately overcome this problem. PSCo argued that the synchronization of costs and revenues can be most closely approximated only in a future test year which can capture all interrelationships, whereas an historic test year is limited by its piecemeal approach.

The construction of the future test year offered in this case began with the issuance, by an executive management team, of corporate objectives, planning goals, and guidelines. Assumptions used in the forecasting and planning process also were generated and reviewed by the Modelers Group, the Assumption Review Committee, and senior executives. On a separate track, the Customer and Sales Task Force developed five-year rolling forecasts of the number of customers and sales by rate class. For some of the classes it relied upon econometric techniques and end-use analysis. For large industrial, special contract, resale/wholesale, and thermal energy customers, the Task Force generated forecasts on an individual basis. These customer and sales forecasts were then reviewed by the division managers, the Vice Presidential Management Committee, and senior executives on an iterative basis. The Task Force solicited feedback on the initial forecasts from a number of geographic divisions of PSCo, which also provided independent estimates of projected numbers of customers to be incorporated into the forecasts.

These customer and sales forecasts were fed, in turn, into the electric demand and supply, and the gas demand forecasts. These combined results became inputs into future cost estimates, operating plans, and capital budgets generated by the Cost Responsibility Centers within PSCo, as well as into the revenue forecasts. Finally, the revenue requirement for the rate case, income taxes, and a corporate financing plan were developed.

This planning and budgeting part of the process went through several recent transformations. First, the time period was expanded from one year to two years. Second, two new software packages, the ACUMEN Integrated Financial Forecasting Package and the Walker MBA Accounting and Budgeting System, were implemented.[13] This planning and forecasting process was not simply a matter of extrapolating past trends. Instead, it represented an active plan for a future decidedly different from even the recent past. Furthermore, these forecasts were not prepared solely for the rate case but for internal management purposes as well. Therefore, in response to suggestions by the parties that the Company had natural incentives to inaccurately construct its numbers to its future advantage, the Company argued

[13] The Walker MBA Accounting and Budget System has been only partially implemented to date.

that it could ill-afford inaccuracies or a test year prepared in bad faith.

In order to increase the comfort level of the parties and the Commission with the forecasting process, PSCo engaged in two additional efforts:

1. Together with Decision Sciences Corporation, PSCo performed statistical analyses of the sensitivity of key assumptions. It found that there was a 40 percent chance of realizing financial results better than the forecasts and a 60 percent chance that the results realized would be worse. From this, the Company concluded that the forecasts were neither unduly optimistic nor pessimistic.

2. Arthur Andersen and Company performed an independent examination of the future test year financial statements. It determined that:

    a. The Company generated technically what is termed a "financial projection," not a forecast, inasmuch as it included hypothetical assumptions as some of the bases for the projections; and,

    b. These financial projections conformed to the 11 guidelines specified by the American Institute of Certified Public Accountants. Arthur Andersen arrived at the latter determination by devoting in excess of two-person years for which it charged approximately $400,000 to the tasks of interviewing a sample of leaders from Cost Responsibility Centers, and engaging in other standard methods of analysis.

{PRIVATE **}**Intervenors**{**tc \l 2 "Intervenors"**}**

A number of Intervenor witnesses addressed the issue of PSCo's forecasting process and its use of a future test year. These included: Gary E. Schmitz, John J. Wright, and Frank C. Shafer (Staff); Ronald J. Binz and David C. Peterson (OCC); Jamshed K. Madan (Intervenor Cities); and John K. Stutz (Colorado Office of Energy Conservation). While they did not offer identical arguments, these witnesses agreed unanimously that an historic test year should be used, instead of PSCo's proposed future test year. According to Intervenors, the advantages of an historic test year include:

1. Known and measurable *pro forma* adjustments and fuel clauses can make it sufficiently forward-looking.

2. It is well understood by all parties and has worked well in the past.

3. It can be audited.

4. Its historical time period does not, *per se*, make it inferior to a future test year.

5. If expenses and rate base are artificially inflated in the historic test year to give the utility an advantage in a rate case, this act imposes a real cost on the utility in the form of lower actual earnings in that time period. Therefore, there are built-in disincentives for the possibility of "gaming" numbers, which give interested parties added confidence in their validity.

6. It does not include hypothetical assumptions.

Intervenors argued that the disadvantages of PSCo's future test year fell generally into four categories. First, PSCo treated its forecasting and its creation of a business plan as a single process. Such treatment raised several issues:

1. Because the outcome of the Integrated Resource Planning ("IRP") and Incentive dockets will impact PSCo's business in the future, it would be necessary to incorporate the results of these dockets into PSCo's business plan. If the plan and

the forecast are indeed the same, these new outcomes as impacted by IRP and incentives would also affect the forecasts. Since these dockets have not yet been completed, the Commission cannot know what impacts they will have on the future test year.

2. PSCo's business plan embodied its corporate objectives and its marketing plan. At this time, the Commission cannot know whether the marketing plan will work, or whether the corporate objectives will be realized. Therefore, the Commission cannot discern whether the forecasts are accurate.

3. The use of the business plan as the forecast, in combination with the use of the forecast as the basis of the test year in a rate case was, in effect, asking the Commission to authorize a revenue requirement and subsequent rates which would assist PSCo in realizing its plan/forecast. This begged the crucial question regarding whether the Commission should be in the business of facilitating the achievement of the plans of the companies it regulates. In addition, the Company's methodology had the additional effect of providing an incentive for every department in the utility to ask for whatever it believed it could possibly need in its forecasted budget.

Second, Intervenors contended that, if PSCo has standard financial objectives as its corporate plan suggests it does, it has the incentive to manipulate its forecasts for the rate case in a manner that overestimates rate base and expenses, and underestimates revenues. These manipulations would have the effect of increasing the amount of additional revenue required to allow PSCo to earn any composite rate of return on capital approved by the Commission. There would be no real cost experienced by the Company as a result of engaging in such manipulations of forecasted values as there would be for comparable manipulations of the same items in an historic test year. In fact, Intervenors pointed to evidence that such over and under-estimations had occurred in PSCo's forecasts. The sensitivity analysis of the forecasts as done by Decision Sciences Corporation indicated that there was a significant risk that PSCo had overestimated operating and maintenance expenses, while there was almost no risk that such expenses had been under-estimated. In addition, for the first two months of 1993, actual revenues had exceeded forecasted revenues, while actual operating and maintenance and capital expenses had fallen short of their forecasted counterparts. These differences were in line with the hypothesized distortions which Intervenors believed would arise from PSCo's process, even if unintentionally. The actual differences between reality and PSCo's monthly forecasts raised concerns since these monthly forecast numbers formed the basis for the first half of the forecasted test year proposed by PSCo in this rate case.

As a third argument against the Company's future test year, Intervenors stated that current circumstances do not warrant the use of a future test year. Precedent teaches that the presence of attrition[14] is used as a primary argument in favor of utilizing a forecasted test year. The presence of attrition can be indicated by the actual rate of return being consistently below the authorized rate. In recent years, the opposite situation generally has held true for PSCo.[15] Furthermore, the standard causes of attrition (*e.g.*, high inflation, high interest rates, rapid expansion in generation facilities) do not currently pertain to PSCo, nor does it appear that they are apt to arise in the near future. Even if PSCo were experiencing attrition, Intervenors argued, allowing PSCo to use a forecasted test year is not the only possible response. For example, the Company could offset the impact of attrition by lowering the cost components within its control.

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[14] The term "attrition" refers to the erosion of a utility's earning power through dramatic increases in costs and/or rate base far in excess of revenue increases due to factors beyond the utility's control (*e.g.*, rapid inflation).

[15] PSCo's actual earnings exceeded its authorized level for 1987 to 1990. This was not true in 1991 due to a ratepayer refund resulting from a negotiated settlement in the last rate case (Docket No. 91S-091EG).

Fourth, Intervenors pointed out their discomfort with the natural information asymmetry at work in the forecasting process, resulting from the obvious fact that PSCo has the most complete knowledge of its own operations. This gives the Company an advantage over Intervenors who had not had the opportunity to build up a comfort level with PSCo's forecasting methods and results over time. Perhaps more significant is the fact that Intervenors did not have the time and resources to engage in a thorough, independent evaluation of PSCo's methods and results. Intervenors contended that it was virtually impossible for an outside party to conduct a complete audit of PSCo's forecasting process because it contained a substantial judgmental component, involved many centers of responsibility (in excess of 750), and generated so many workpapers (in excess of 500,000). For example, Arthur Andersen's evaluation required time in excess of two-person years at a cost to PSCo in excess of $400,000 and still was insufficient in many respects. Intervenors simply did not have the time and money to duplicate even this level of effort, let alone one that would result in a more complete evaluation.

In addition to these general, methodological criticisms, the Intervenors also observed that: (1) PSCo's Board of Directors did not approve the numbers for the second half of the future test year, and (2) the difference between the future and historic test years ($47.3 million), which was caused primarily by differences in expenses, could not be accounted for or explained by known and measurable adjustments because these were already included in the historic test year.

In addition to the evaluation of the relative merits of the test years discussed here, the Intervenors provided two recommendations related to the possibility of using a forecasted test year in a future rate case:

1. The Commission could open a docket to collect and compare PSCo forecasts with actual results for a three-year period so that other parties can acquire better insight into the accuracy of PSCo's forecasts.

2. If PSCo files a forecasted test year in a future rate case, it should provide a line-by-line comparison with an historic test year, together with adequate explanations for all deviations.

{PRIVATE **}**PSCo Rebuttal**{**tc \l 2 "PSCo Rebuttal"**}**

PSCo responded to the Intervenors' preference for the use of an historic test year. First, the Company argued that *pro forma* adjustments cannot capture all differences between future and historic test years. For example, in this case, a large non-revenue producing investment (the baghouse at the Commanche power plant, which went into service after the end of the historic test year but which appeared in the future test year) accounted for a significant difference between the two test years. Second, despite the fact that an historic test year can be audited, the Company contested its value as an accurate representation of the future.

PSCo also provided the following rebuttal to Intervenors' criticisms of its forecasting process and its use of the future test year:

1. While the outcomes of the IRP and incentive regulation dockets do have an effect on the future, and are at this point unknown, the same uncertainty applies to an historic test year.

2. PSCo's market plan did not drive the customer and sales forecasts; the two were generated separately.

3. The historic data did not necessarily indicate that PSCo under-estimated future electricity sales. For example, while it was true that the sales forecasts for the first quarter of 1993 turned out to be less than the actual sales, this divergence could be explained by the fact that the quarter was colder than normal. The forecasting process did not

include forecasts of weather. Instead, normal weather conditions were assumed. If the actual sales were adjusted to eliminate the effect of the abnormally cold weather, the resulting numbers were very close to their forecasted counterparts.

4. While there may be a theoretical reason for PSCo to under-estimate sales when generating a forecasted test year for regulatory purposes, it would never do so intentionally because: (a) it is a company with integrity; (b) it uses these same forecasts for internal corporate decision-making, so it cannot afford to mislead itself by failing to plan for sufficient resources to serve actual demand; and (c) it does not want to jeopardize its chance of using a forecasted test year in the future.

5. While PSCo's actual rate of return exceeded the authorized level for several years beginning in 1987, this inequality did not reflect the absence of attrition, but rather was caused by a combination of other factors which resulted in cost decreases and/or revenue increases. PSCo may experience attrition in the near future because it is planning annual capital expenditures in excess of $300 million for each of the next five years.

6. PSCo's forecasting process is not as complicated as Intervenors suggest. There is as much paperwork related to the historic test year as to the future test year. The real issue is that the Intervenors were more comfortable with PSCo's accounting system than with its planning, budgeting, and forecasting system.

{PRIVATE **}**Ruling on Future Test Year**{**tc \l 2 "Ruling on Future Test Year"**}**

The Commission rejects the future test year provided in this case in favor of an historic test year with *pro forma* adjustments. However, the Commission does not wish to preclude, nor can it preclude, the possibility that the Company may successfully propose the use of a future test year in subsequent rate cases. Our rejection of the future test year is based upon our concurrence with certain Intervenor criticisms. In particular, we note:

1. The Company did not satisfactorily demonstrate that the circumstances in which it finds itself in the present or near future necessitate the use of a future test year. For example, we find that the Company is not facing a serious threat of attrition which cannot be appropriately addressed in other ways. Moreover, we agree with Intervenors that an historical test year with *pro forma* adjustments is, at this time, superior to a future test year for ratemaking purposes. The Company's evidence did not convince us that the historical test period, with appropriate adjustments, is not sufficiently representative of the effective rate period.

2. Even if it had so demonstrated, the Company did not provide documentation of its forecasting process sufficient for the Commission to thoroughly understand and evaluate the process. For example, in generating its customer and sales forecasts, the Company relied to some degree upon econometric techniques. Yet, it failed to provide any documentation of the equations used, or the associated statistics with which to analyze those equations. The Company also could have indicated how much the forecasts from these equations were altered by each level in the management review process in arriving at the final numbers. It also could have explained the criteria against which proposed alterations were judged. Similar detail would have enhanced the Commission's understanding of the forecasting process, but was unavailable

throughout the Company's presentation. In addition, evidence that would explain in detail the differences between a future test year and an historic test year would have been helpful.

However, the foregoing comments are not made to suggest that PSCo took no steps to increase the possibility that the Commission may rely on its forecasting process. Both the Arthur Andersen audit and the Decision Sciences Corporation sensitivity analysis helped in that regard, but also raised questions concerning the appropriate level of materiality for the regulatory process and the possibility of under- or over-estimation of the components of the revenue requirement.

The Commission will not adopt Staff's recommendation to open a docket to monitor PSCo's actual performance in comparison to the forecasted values propounded in this rate case. While such a comparison would be a useful part of any future PSCo filing relying upon a forecasting process, the Commission is not in a position to underwrite such analysis for experimental purposes.

Finally, the Commission should mention here that, apart from the two types of test years filed in this docket (*i.e.*, future and historic), the Commission considers a current test year to be a conceptually acceptable alternative, especially where valid concerns exist regarding use of an historic test year. In a subsequent rate case, the Company may consider using a test year beginning with 12-months of forecasted data which would become a combination of forecasted and historical numbers as the case proceeded. Alternatively, the Company could begin with such a combination test year which would become more heavily historical as time passed. One of these "current" test years might provide a promising mixture of comfort and flexibility acceptable to the parties and the Commission. Of course, the most appropriate test year for a rate case is dependent upon the circumstances in which a company finds itself at the time it is prepared to proceed with a rate case.

{PRIVATE **}**RATE BASE**{**tc \l 1 "RATE BASE"**}**

The Commission's specific findings regarding the Company's electric, gas, and steam rate base are set forth in Attachment B to this decision. The adjustments disputed by the parties and the Commission's decisions regarding those disputes are set forth in this section of the decision.

{PRIVATE **}**Year-End Rate Base**{**tc \l 2 "Year-End Rate Base"**}**

In its historical test year, the Company used a year-end rate base. Staff witness John Wright used an average rate base methodology (13-month average). Predicated upon that methodology, Mr. Wright made a variety of adjustments to rate base which--when combined with Staff witness Frank Shafer's adjustments to income statement--reduced the revenue requirement approximately $2 million. Staff argued that average rate base more closely matches the revenue stream resulting from test year operations than the "snapshot" of rate base provided by a year-end rate base.

Staff maintains that the year-end method should be used only in "extraordinary" or "emergency" circumstances since average rate base more accurately reflects the interrelationship between test year investment, revenues, and expenses. Staff suggested that the presence of attrition would be cause to use the year-end method, but where such attrition is not a significant factor, as here, no reason exists to depart from the traditional average methodology.

The Company responded. First, according to Company witnesses, attrition presently is affecting earnings, and will continue to do so in the rate-effective period. The Company pointed out that there were major investments made which were not reflected in the historical test year.[16] PSCo witness Ronald Darnell also suggested that use of year-end rate base, rather than average, is consistent with ratemaking principles in that the purpose of a test period with *pro forma* adjustments is to develop

[16] Two projects involving substantial capital expenditures, the Commanche baghouse and the new Customer Information System, were in service at the time of hearings in this case. However, the investment for these undertakings was not accorded full ratemaking treatment in the historical test period inasmuch as the projects were not in service during the test year. Inclusion of these investments in "plant in service" would have entailed out-of-period *pro forma* adjustments to rate base, a practice which traditionally has not been approved.

a forward look at the utility's cost of service. Therefore, says Mr. Darnell, an historic test period should include the most current rate base--a year-end rate base.

In previous decisions, the Commission has stated that in most cases average rate base more accurately reflects the relationship between test year investments, revenues, and expenses than a year-end rate base. However, the Commission also has acknowledged in prior decisions that the use of year-end rate base may be proper in special circumstances, for example, to combat some potential sources of attrition beyond control of the Company, such as growth in plant, especially plant that is non-revenue producing like the Customer Information System ("CIS").

We agree with the Company that in this proceeding average rate base does not account for significant investments which are now in service. For example, the Company has installed and placed into service approximately $50 million of pollution control equipment, the Commanche baghouse, which was not included in the historical test year. In his oral rebuttal testimony Mr. Kelly noted that the Commanche baghouse was in service (*i.e.*, used and useful) and that the revenue requirement impact of allowing this investment into rate base would have been approximately $5.0 million. The Company also pointed out that the new CIS, entailing total capital expenditures of approximately $52 million, was implemented in August 1993, also outside the test period.[17]

We find that these major capital expenditures are out-of-the-ordinary and are not sufficiently accounted for in the average rate base method. Moreover, these significant and necessary capital investments are non-revenue producing. A qualitative consideration of these expenditures in this decision through the use of a year-end rate base entails no risk of unduly distorting test year interrelationships. In view of these findings, we conclude that in this specific case, the year-end figure should be used, as there is evidence that there will be some attrition beyond the control of the Company.

{PRIVATE **}**Customer Information System**{**tc \l 2 "Customer Information System"**}**

In his direct testimony, Staff witness John Wright advocated exclusion of approximately $17.8 million from Construction Work in Progress ("CWIP") which was, in Staff's view, an excessive amount booked to CWIP for development of the Company's CIS software. In the historic test year, the Company's rate base contained approximately $38.8 million in CWIP for development of CIS. PSCo witness Steve Brown described the development of the original CIS which was designed to automate the process of calculating and

[17] As discussed, *infra*, approximately $38 million of CIS expenditures were included in CWIP in the historical test period. However, since an AFUDC offset also was included, the rates set in this case allow for recovery of only a minimal amount of these expenditures.

generating customer billing statements, and to answer basic inquiries about these bills. Over time, the system was expanded to support every major customer-based activity occurring at PSCo. At the time of the hearing, the original system had been in service for over 20 years, but according to Mr. Brown's testimony, CIS was completely obsolete and "at the end of its useful life." For example, according to Mr. Brown, much of the system software used when the original CIS was built was no longer in general use, and certain base component pieces of system software used by CIS would not be supported by the vendor in the very near future.

Mr. Brown also pointed out that CIS is a core system and an absolute requirement for the Company to continue doing business. The system provides for virtually all functions involving interaction with customers (*e.g.*, meter reading and billing; initiating, tracking, and concluding customer outages, trouble, and service calls; establishing special programs such as Budget Billing and the Low-Income Energy Assistance Program; issuance of refunds; processing of collections, etc.).

Staff did not dispute the critical nature of CIS to the Company's operations. However, in advocating exclusion of a portion of CIS costs from CWIP, Staff questioned the prudence of the total expenditures for the new system. Specifically, Staff noted that although the preliminary estimate for the new system was $21 million, the final cost was estimated at $52.3 million. Of this total amount, the Company included $38.8 million in CWIP, with an AFUDC offset, in the historical test year. Staff suggested exclusion of the $17.8 million "cost overrun" from CWIP. This amount represents the difference between the preliminary estimates for the project and the amount included in CWIP in the historical test year.

At hearing, Staff presented a number of documents which showed that additions to the CIS budget were requested on numerous occasions and were approved. The Company offered little or no evidence which demonstrated that the Company performed appropriate cost/benefit analysis and quantified the expense and revenue impacts before beginning the project; that management adequately monitored cost increases for the project during its deployment; or how the additional budget increases for the project were justified within the Company. Indeed, the relatively limited evidence presented to the Commission on these issues was presented by Staff, and was acquired in the audit process. Staff concluded that the Company should not be allowed to earn a return on CIS investment until it demonstrates that the expenditures were prudent.

We share some of Staff's concerns. The cumulative effect of the evidence is to leave the impression that, while the Company's executives' management decision to replace the CIS system was justified and well-timed, and subsequent decisions to increase the approved expenditures for the system were made after executive receipt of appropriate information and analysis, Company record-keeping for the project was shoddy and showed an uncommon (for the Company) disregard for accountability. Therefore, we are unable to conclude, based upon the present record, that the accrued costs for CIS were prudently incurred.

In rebuttal, the Company pointed out that there is virtually no rate impact on customers as a result of including CIS in CWIP with the accompanying AFUDC offset, the manner in which these expenses are treated in the historical test year. The Company also noted that the new CIS was installed in August 1993, and is now operational. The Company intends to evaluate CIS's operations and measure associated efficiencies after one year. Since ratepayers will be relatively unaffected by the present accounting treatment, PSCo suggested that the costs be retained in CWIP and that the Commission evaluate the prudence of these expenditures at the time the Company seeks to include the expenditures in plant in service.

We agree that it is premature to disallow all or part of CIS costs at this time. This is especially true in light of the pending evaluation of the project, and because ratepayers will not be affected by the present accounting methodology being used for the project. Furthermore, in fact, ratepayers are, likely to benefit in some measure from increased effectiveness and improved customer service during the "evaluation year." Therefore, we will allow the full historical test year amount ($38.8 million) to remain in CWIP at the present time. The Company is on notice regarding the Commission's concerns arising out of its poor record-keeping, and also regarding the need to document the prudence of the expenses incurred for the new CIS. The Company should be prepared to address these concerns <u>at the time it seeks rate recovery for CIS</u> as it will be its burden to establish that the costs for the system were prudently incurred.

<u>**{**PRIVATE **}**Construction Work in Progress**{**tc \l 2 "Construction Work in Progress"**}**</u>

OCC witness David J. Effron objected to the amounts of CWIP which the Company proposed to include in rate base as well as the AFUDC included in operating income in the Company's filing. In the Company's historical test year, it included $168,738,000 of CWIP in electric rate base (based upon a requested rate of return of 10.29 percent). Therefore, the income requirement associated with electric CWIP was $17,363,000. The AFUDC included in electric operating income was $10,402,000, an amount $6,961,000 less than the income requirement associated with the inclusion of CWIP in rate base. For the Gas Department, the Company included

$48,002,000 of CWIP in rate base. The income requirement associated with this CWIP was $4,939,000, an amount $2,221,000 greater than the AFUDC included in gas operating income.

Mr. Effron contended that the treatment of CWIP and AFUDC should not create a revenue requirement which is solely the result of a mismatch between the CWIP in rate base and the AFUDC in operating income. Therefore, Mr. Effron proposed adjustments to both CWIP and AFUDC amounts. Essentially, Mr. Effron recommended that lesser amounts of CWIP be included in rate base and greater amounts of AFUDC be included in *pro forma* operating income. *See* Exhibit FF, at 18.

The three options for treating CWIP and AFUDC were explained on pages 9 and 10 of Mr. Effron's direct testimony. Briefly, these options are: (1) exclusion of CWIP from rate base with no recognition of AFUDC in operating income; (2) inclusion of CWIP in rate base with AFUDC being included in *pro forma* operating income; and (3) inclusion of CWIP in rate base with no recognition of AFUDC. The testimony in this case (Effron, Darnell, Wright) correctly noted that the Commission has in the past followed option 2. If the AFUDC rate is the same as the authorized rate of return, and all CWIP accrues AFUDC, option 2 would result in substantially the same revenue requirement as option 1. That is, ratepayers would not pay a current return on investment in facilities not yet in service, and rate recovery for new construction, including carrying costs, would be deferred until the plant was placed into service. Controversy has arisen regarding this issue because there is not a precise match between the CWIP included in rate base and the AFUDC included in operating income.

The reasons for this difference between CWIP and AFUDC are varied. For example, to the extent AFUDC is not calculated on short-term or small construction projects, on AFUDC previously included in CWIP, or if AFUDC is delayed on a booking basis, ratepayers pay a current return on some level of investor-supplied construction funds. This amount of current return from ratepayers is known as "slippage." The witnesses pointed out that the Commission has long recognized "slippage," even in choosing to implement the methodology described as option 2. *See* Darnell rebuttal, at 6-7.

As set forth in Mr. Wright's testimony (Exhibit ZZ, page 32), requiring an AFUDC offset to earnings for long-term construction projects, but allowing a level of current earnings via "slippage," has been allowed in all PSCo rate cases at least since I&S Docket No. 935 in 1975. The Commission held in Decision No. C80-2346:

> The fact that a return on a portion of the needed construction expenditures advanced by the investor is being paid for by current customers (that portion being measured by "slippage") enhances the cash flow position

> and resulting financial strength of the utility, and may result in lower financing costs to all ratepayers, current and future.

Furthermore, we find that the Company's treatment of CWIP and AFUDC is consistent with the stipulation approved by the Commission in Decision No. C91-1540 (Exhibit 330), which requires the Company to account for CWIP and AFUDC in accordance with the above-articulated policy. In our view, the OCC is recommending substantial change of a long-standing policy when there is reason to continue the policy. We, therefore, reject the proposed adjustments.

{PRIVATE **}**Contributions in Aid of Construction/Deferred Income Taxes**{**tc \l 2 "Contributions in Aid of Construction/Deferred Income Taxes"**}**

In his direct testimony, OCC witness Effron proposed to modify the Company's balance of accumulated deferred income taxes related to contributions in aid of construction ("CIAC"). Mr. Effron explained that, pursuant to the Tax Reform Act of 1986, the Company is required to pay income taxes on CIA. Because such contributions are included in currently taxable income but not in book income, a temporary, tax timing difference is created. This particular tax timing difference has the effect of increasing taxable income relative to book income. In 1987, 1988, and the first half of 1989, the Company utilized flow-through accounting for this timing difference. According to Mr. Effron, this flow-through accounting had the effect of increasing the current income tax expense included in cost of service. However, in mid-1989, the Company changed to deferred accounting for this timing difference. The change to deferred accounting was done prospectively <u>and retroactively</u> to the beginning of 1987.

To implement the deferred tax accounting retroactively, the Company reversed income tax expenses that had been recognized for <u>1987</u>, <u>1988</u>, and the <u>first half of 1989</u>. In addition, the Company made an offsetting charge to its accumulated (prepaid) deferred income tax account. These accounting entries resulted in a credit (for income tax expenses previously recognized that were being reversed) to income tax expense, and a charge to accumulated deferred taxes of over $10 million. The charge to the accumulated deferred income tax account resulted in a reduction of deferred income taxes which would otherwise be used to reduce rate base.

In Mr. Effron's opinion, these circumstances result in "double recovery" by the Company of income tax expenses related to the CIAC. The first recovery occurred when the Company recognized the income tax expense on a current basis and included these expenses in its cost of service. The second recovery would occur through the inclusion of the deferred tax debit balance in rate base (*i.e.*, the reduction in the deferred tax account) and the amortization of the deferred tax debit balance as an expense. To avoid this purported double recovery, the OCC proposed that the amount of the deferred tax debit balance that previously had been expended be eliminated from rate base, and that the amortization of the deferred tax debit balance be eliminated from expenses. The effect of this adjustment would be to reduce the Company's Electric Department rate base by $6.5 million and its Gas Department rate base by $1.9 million.

In Mr. Gilliam's rebuttal, the Company disputed the OCC's suggested adjustment. Mr. Gilliam stated that the disputed income tax expense for the first half of 1989 was not included in cost of service because that period was never part of any test year used in setting rates. With respect to calendar year 1988, Mr. Gilliam pointed out that the Company made a specific rate reduction to account for the previously incorrect flow-through treatment of income taxes related to CIAC. This rate reduction, effective June 17, 1989, was part of a rate decrease made pursuant to a prior settlement agreement with Staff and the OCC. *See* Gilliam Rebuttal, at 13-14 (Exhibit Z). According to Mr. Gilliam, this rate reduction was approximately $1 million more than called for in the settlement agreement.[18] *See* Exhibit 233. Regarding the

[18] The settlement agreement approved by the Commission in Decision No. C88-256 provided for revenue reductions related to calendar test periods 1987 and 1988. Each year used a different formula for determining the revenue reductions to be put into effect through a negative rate rider for a one-year period beginning April 1 of the following year. The revenue reduction resulting from the 1988 test year was to be negative 3.19 percent pursuant to

1987 test period, Mr. Gilliam noted that, pursuant to the prior settlement agreement, the rate reduction would have been $700,000 more if taxes on CIAC had been normalized properly.

We agree with the Company's position on this issue. Briefly, we find that for portions of the years 1987-1989, there was no "first recovery" of income tax expense associated with flow-through treatment of CIAC. This is true because effective rates, at least for a portion of this time, were not based upon a test year involving any of these periods. Additionally, we accept the Company's argument that, for 1987 and 1988, customers were compensated through rate reductions which were implemented by the Company in accordance with its agreement with the OCC and approved by the Commission. Given these findings, we reject the OCC's proposed adjustment.

{PRIVATE **}**Deferred Colorado Investment Tax Credit**{**tc \l 2 "Deferred Colorado Investment Tax Credit"**}**

Mr. Effron recommended on behalf of the OCC that the Commission remove accumulated deferred state investment tax credits ("ITC") from rate base. Mr. Effron explained that the Company's accounting treatment for Colorado ITCs has been

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the settlement agreement. In fact, on June 17, 1989, the Company adjusted the rider to negative 4.29 percent to account for the incorrect flow through of income taxes on CIAC. This 1.1 percent adjustment further reduced revenues by $8.9 million.

identical to that used for federal ITCs. Specifically, when the credits were utilized, they were deferred on the Company's books of account and amortized ratably over the life of the assets which generated the credits. The Company has made no rate base deduction for accumulated state deferred ITCs.

In Mr. Effron's view, the accumulated deferred state ITCs represent non-investor supplied funds. That is, utilization of state ITCs has reduced the amount of state income taxes currently payable. This savings in state income taxes has not been flowed through to ratepayers because the Company recorded a deferred tax expense when the state investment tax credits were utilized, and the deferred tax expense has been included in the Company's cost of service for ratemaking purposes. According to Mr. Effron, since this accounting for the state ITCs has provided the Company with non-investor supplied capital, the credits should be deducted from rate base. The Company disputes this recommendation.

In essence, the issue here is whether Colorado laws permit the type of accounting treatment for state ITCs suggested by Mr. Effron. The OCC concedes that federal law precludes this treatment for federal tax purposes. Under federal law, no ITC would be allowed for the Company if the Commission reduced rate base by any part of the credit. This result would be detrimental to ratepayers. However, the OCC argues that no similar state law precludes deduction of the ITCs from rate base for state tax purposes.

We will reject the OCC's suggestion. First, we note that the Commission has applied consistent regulatory treatment to both federal and Colorado ITCs utilized by PSCo for many years. Additionally, we observe that Colorado statutes require corporations to use the same accounting methods for State tax purposes, as used for federal tax purposes. *See* sections 39-22-111(3) 39-22-306, C.R.S. Under the election made by the Company for federal tax purposes, as required by Internal Revenue Code § 46(f)(2), rate base may not be reduced by any part of an ITC.

In summary, we believe that the suggestion of the OCC may jeopardize the Company's ability to take advantage of State ITCs. This result would be detrimental to ratepayers, as explained by PSCo witness W. Wayne Brown in his rebuttal. For these reasons, the suggestion of the OCC is refused.

{PRIVATE **}**Employee Retirement Income Security Act Pension Funding**{**tc \l 2 "Employee Retirement Income Security Act Pension Funding"**}**

As part of its rate request, the Company included in its rate base certain amounts for prepaid pension assets. As Staff witness John Wright explained, prepaid pension assets and liabilities arise when the level of pension contributions calculated under the actuarial assumptions required by the Internal Revenue Service ("IRS") and the Employee Retirement Income Security Act ("ERISA") differ from the level of annual pension expense calculated under the actuarial assumptions required by Generally Accepted Accounting Principles ("GAAP"). In the Company's case, IRS- and ERISA-mandated pension contributions have exceeded pension expenses derived pursuant to accounting principles. Currently, the Company recovers in rates, pension expenses based upon GAAP, instead of recovering the greater expenses mandated by the IRS and ERISA. Shareholders are required to fund the additional amounts indicated by ERISA and the IRS. In order to compensate investors for the additional funds they supply to meet the higher contribution levels, the resulting prepaid assets are an appropriate addition to rate base.

However, in its filing, the Company projected the balance of prepaid pension assets as of December 31, 1993 (15 months outside the test year), and included this amount in rate base. Both Staff and the OCC object to a December 31, 1993, valuation date for these prepaid pension assets.[19] The parties argue that it would

[19] In prefiled testimony, OCC witness Effron also suggested that the prepaid pension cost included in rate base should reflect the net-of-tax amount. This issue was settled in a stipulation between the Company and the OCC (Exhibit 251). *See* discussion, *supra*.

be improper to selectively project the prepaid pension balance beyond the test year. We agree. Therefore, the prepaid pension assets to be included in rate base shall be determined as of the end of the historical test year, September 30, 1992, consistent with the other elements of rate base.

{PRIVATE }RATE OF RETURN{tc \l 1 "RATE OF RETURN"}

{PRIVATE }Rate of Return on Equity{tc \l 2 "Rate of Return on Equity"}

As in all general revenue requirement cases, the Commission must determine the proper return on equity ("ROE") for the Company. Likewise, as in past cases, this issue was one of the most contentious. In this proceeding, five witnesses (listed below with their recommendations), presented testimony regarding the proper ROE.

WITNESS	RECOMMENDATION
Dr. Avera (PSCo)	13.00%
Mr. Ekland (Staff)	10.79%
Mr. Copeland (OCC)	10.75%
Dr. Stolnitz (DOE)	10.70%
Mr. Eisdorfer (CII)	9.30%

For the reasons discussed herein, we find that the fair and reasonable rate of return for the Company's equity investors in the Company is 11.00 percent.

Our determinations are guided by the Supreme Court's observations in *Federal Power Commission v. Hope Natural Gas*, 320 U.S. 591 (1944). There, after noting that the fixing of "just and reasonable rates" involves a balancing of investor and consumer interests, the Court stated:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock . . . [*citation omitted*] . . . . By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

Federal Power Commission v. Hope Natural Gas, *supra*, at 603.

All rate of return witnesses employed a discounted cash flow ("DCF") analysis method, to one extent or another, in order to reach their conclusions regarding their recommended ROE.[20] DCF

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[20] DCF methods are based upon the premise that the price of a company's common stock is equal to the present value of the expected cash flows (*i.e.*, future dividends and stock price) that will be received by the investor while holding the stock, discounted at the investor's required rate of return. Stated otherwise, according to DCF theory the investor's required return on common equity equals the dividend yield plus the expected rate of growth in the dividend. This theory is represented mathematically as follows:

$$\mathbf{k = D/P + g}$$

where **k** is the cost of equity (*i.e.*, the investor's required return), **D/P** is the dividend yield (the dividend divided by market price of the stock), and **g** is the expected rate of growth in the dividend.

analysis is a well established regulatory method for estimating the cost of equity capital. In the past, this Commission has determined that DCF analysis is an acceptable methodology for deriving a fair ROE.

{PRIVATE }Dr. William Avera{tc \l 3 "Dr. William Avera"}. The Company's ROE recommendation was presented by Dr. William Avera. Initially, Dr. Avera conducted a (DCF) analysis applied to PSCo and a group of 28 other combination electric and gas utilities. He calculated a dividend yield of 7.4 percent for PSCo based upon the current and expected dividend of $2 per share, and a stock price of $27 per share. This was the current price, and the average price of Company common stock over the last 12 months prior to the filing of testimony.[21]

In order to estimate investors' long-term growth expectations, Dr. Avera considered a number of financial elements, both historical and projected, of the Company's operations. Specifically, Dr. Avera surveyed five- and ten-year growth rates in PSCo's earnings per share, dividends per share, book value per share, and selected stock prices. He next examined the relationship between retained earnings and earned rates of return,

[21] These calculations were presented in prefiled testimony. At hearing, Dr. Avera conceded that some of these estimates had changed based upon more current information such as changes in the Company's stock price. *See* discussion, *infra.*

reasoning that this relationship is an indication of the type of growth investors might anticipate from reinvestment of earnings within the Company. Finally, Dr. Avera assessed the growth rates projected for the Company by investment analysts. The rates of growth for the Company under these methods were varied. For example, under the first method growth rates ranged from 0 to 7 percent.

Dr. Avera then applied subjective "judgment" to limit the range of growth rates to those he considered plausible, which, in essence, resulted in dismissal of all derived growth rates less than 3 percent. Dr. Avera's stated reason for doing so was that these rates of growth, when added to the derived dividend yield, resulted in cost of equity estimates less that 10.5 percent. In Dr. Avera's view, risk premium analysis indicated that such estimates are fundamentally unreasonable.[22] After narrowing the range of growth rates, Dr. Avera ultimately determined that 4.5 to 5.5 percent were reasonable rates to use in his DCF analysis. Added to the derived 7.4 percent dividend yield, this DCF analysis indicated a cost of equity between 11.9 to 12.9

[22] Growth rates of approximately 3 percent, under DCF analysis, would have produced a cost of equity less than 10.5 percent. Dr. Avera observed that this return was not "appreciably" greater than the November 1992 yield on triple-B public utility bonds, which, at the time of his prefiled testimony was 9 percent. As discussed, *infra*, Dr. Avera concluded that investors require a "substantially" higher return for holding common stock than for other securities such as bonds. Therefore, Dr. Avera contended, 10.5 percent could not be a fair and reasonable ROE capital since, in his view, investors would not accept a ROE barely 1.5 percent above the yield on less risky securities.

percent for the Company.[23]

Even after performing this multi-faceted analysis for deriving the cost of equity for the Company, Dr. Avera's final recommendation essentially ignored the results of the analysis. He suggested that the DCF method does not produce reasonable results in light of current economic conditions in the country. Dr. Avera argued that "current capital markets are distorted as a result of the Fed's attempts to ignite a recovery by lowering short-term interest rates." He concluded that, in current economic times, DCF is not providing acceptable cost of equity estimates because many of the indicated rates are not substantially higher than the yields on less risky capital investments such as utility bonds.[24] Since, in his view, the economic conditions which are causing DCF results to be unrealistic are temporary, Dr. Avera performed one other estimate of growth rates which relaxed the DCF assumption that "investors expect the same growth rate to prevail from now until infinity." That is, Dr. Avera attempted to estimate both short- and long-term growth expectations. To do so, he averaged Institutional

[23] This same DCF methodology applied to the 28 other combination electric/gas utilities studied resulted in average cost of equity estimates between 6.02 and 15.61 percent.

[24] According to Dr. Avera's testimony, investors can be induced to hold more risky investments only if they expect to earn an additional return to compensate them for their added risk. This is known as the risk-return tradeoff principle.

Brokerage Estimate Service ("I/B/E/S") projected growth rates for the Company through 1998 with certain estimated rates of growth in Gross Domestic Product ("GDP") between 1998 and 2017. This computation resulted in a growth rate of 5.7 percent for the Company, and an estimated cost of equity of 12.9 percent.

Dr. Avera then proceeded with his risk premium analysis.[25] He performed this analysis by utilizing the risk premiums for utilities reported in a number of studies in the academic and trade literature. Based upon these risk premium studies, Dr. Avera estimated that cost of equity for the Company ranged from 11.63 to 15.51 percent, and averaged 13.55 percent. Notably, several of Dr. Avera's risk premium calculations, based upon the utilized studies, assumed that equity risk premiums tend to move inversely with interest rates. That is, when interest rate levels are relatively high, equity risk premiums narrow. Conversely, when interest rate levels are low, as they are currently, risk premiums widen. This assumed inverse relationship between interest rates and equity risk premiums is central to Dr. Avera's testimony. Other witnesses disputed this basic premise of Dr. Avera's analyses, which resulted in greater equity risk premiums

[25] As Dr. Avera explained, risk premium methods estimate the cost of equity by adding an equity risk premium to observable bond yields. This equity risk premium is the additional return investors require to bear the greater risks associated with common stocks. Under risk premium analysis, the required rate of return for any particular asset is a function of the yield on risk-free assets and its relative risk to risk-free investments, with investors demanding correspondingly larger risk premiums for assets bearing greater risk.

for the Company.

Based upon the many and varied analyses he performed, Dr. Avera eventually estimated that the minimum required ROE for PSCo is in the range of 12.25 to 13.25 percent. He then suggested that, in selecting a return within this range, the Commission should consider two additional factors:

1. Flotation costs associated with past and prospective common stock issuances by the Company are not recovered in rates.

2. The calculated cost of equity estimates generally do not account for PSCo's additional purchased power risks to the extent the Company relies more heavily on purchased power than the other comparable companies.

In consideration of his cost of equity computations and the additional relevant factors identified above, Dr. Avera recommended a ROE at the upper end of his range, 13.0 percent.[26]

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[26] At hearing, Dr. Avera conceded that interest rates had fallen, and the price of the Company's stock had risen since the filing of his testimony, and that, all things being equal, these two factors would indicate that PSCo's cost of equity had dropped approximately .5 percent to a range of 11.75 to 12.75 percent. However, Dr. Avera argued that electric utilities still are perceived by investors as having some added risks. Allocating an extra .25 percent to account for this additional risk, he still recommended a 13.0 percent return.

{PRIVATE }Basil Copeland (OCC){tc \l 3 "Basil Copeland (OCC)"}. OCC witness Basil Copeland recommended a ROE of 10.75 percent. The principal basis for his recommendation was a DCF analysis supplemented by a Capital Asset Pricing Model ("CAPM") and other considerations concerning current capital market costs. In his DCF analysis, Mr. Copeland used the same group of comparable companies used by Dr. Avera. To determine the growth component for his model, Mr. Copeland utilized a number of investment analysts' projections (*e.g.*, *Value Line, Value Screen* database, *Institutional Brokerage Estimate Service* forecast). For the yield component, Mr. Copeland sought to avoid estimates based upon spot market prices. Therefore, he used six-month average yields.[27]

For his risk premium analysis, Mr. Copeland employed a CAPM method. Under this approach, the market risk premium is adjusted to reflect the risk of a specific stock using the stock's beta coefficient.[28] This adjusted risk premium is then added to an appropriate "risk-free" rate, in this case the yield on long-term government bonds which was 6.8 percent at the time of prefiled testimony.

[27] This analysis produced a growth rate of 2.8 percent and a yield of 7.0 percent for the Company.

[28] "Beta" is a measure of a stock's covariation of return compared to the market as a whole, and is considered a measure of risk in finance and portfolio theory. A beta of 1.0 means that a stock's return tends to vary up and down by the same percentage as the market as a whole, and would indicate a stock of average market risk.

Mr. Copeland's DCF analysis produced an estimate of 8.7 percent and the CAPM method a 9.1 percent cost of equity for the group of companies studied. According to relevant indicators, since PSCo is of slightly higher risk than the group as a whole, Mr. Copeland reasoned that the Company's cost of equity is in the range of 9.0 to 9.5 percent. Nevertheless, Mr. Copeland recommended a ROE for the Company of 10.5 to 11.0 percent. The reason for this suggestion was Mr. Copeland's belief that, with a 9.0 to 9.5 percent allowed return, the Company's interest coverage would decline "precipitously." His recommended return, Mr. Copeland asserted, would allow PSCo to maintain its current bond rating (BBB+).[29] The midpoint of his recommended range is 10.75 percent.

{PRIVATE **}**Robert Ekland (Staff)**{**tc \l 3 "Robert Ekland (Staff)"**}**. Staff witness Robert Ekland also performed a DCF analysis for the Company and a group of combined electric and gas companies.[30] To derive the dividend yield, Mr. Ekland averaged

[29] He further advised that as long as interest coverage considerations drive the allowed rate of return, the appropriate standard for evaluating coverage should be whatever is required to maintain the existing BBB+ rating. Thus, Mr. Copeland rejected a return which would allow the Company to improve its bond rating to A, reasoning that this return would be unfair to ratepayers.

[30] Mr. Ekland explained that the use of a comparable group in DCF analysis is to compare the derived rate of return for PSCo to determine if the Company's return falls in the range of returns for that type of utility. Dr. Stolnitz objected to such comparative analysis. *See* discussion, *infra*.

the previous year's dividend and the upcoming year's projected dividend. The stock price used in his dividend calculation was the average daily closing price of PSCo's and the other comparable utilities' stock. The average closing stock price was calculated from the eve of the most recent ex-dividend date prior to the filing of his testimony, back to the previous ex-dividend date.[31] For the growth component of his analysis, Mr. Ekland utilized *Value Line's* estimated growth rate in earnings (2.50 percent for the Company).

The results of Mr. Ekland's analysis indicated a cost of equity for PSCo of 9.44 percent, and an average cost of equity for the comparable companies of 9.53 percent. However, Mr. Ekland concluded that 9.44 percent would not be an appropriate allowed return for the Company. Such an allowed return, in his view, would likely cause PSCo's stock price to fall below book value because of investor shock. This serious investor reaction could happen because a return of 9.44 percent would result in earnings per share of $1.96. Since the Company's present dividend is $2.00 per share, an authorized return of 9.44 percent would not enable PSCo to maintain its current dividend. Mr. Ekland suggested that an adjustment is necessary to allow the Company the opportunity to maintain its dividend and, therefore, a market to book ratio of 1.

[31] For PSCo, this produced a dividend yield of 6.94 percent.

Mr. Ekland submitted that the appropriate ROE lies between 9.44 percent, the result produced by DCF analysis, and 12.14 percent, the return which would enable the Company to fulfill investors' expectations of a $2.00 dividend and growth in earnings of 2.5 percent. Both ends of the range, in Mr. Ekland's opinion, were unreasonable. As discussed above, Mr. Ekland found 9.44 percent unreasonable because it would cause investor shock and drive market to book value below 1. However, Mr. Ekland believes that although 12.14 percent would fulfill investor expectations with respect to the current dividend and projected growth, it would continue to support an excessive market to book ratio of 1.55. Therefore, Mr. Ekland recommended 10.29-11.29 percent as a reasonable range for ROE. He then selected the midpoint of this range, 10.79 percent, as the point estimate for the appropriate return.

{PRIVATE **}**Dr. George Stolnitz (DOE)**{**tc \l 3 "Dr. George Stolnitz (DOE)"**}**. In his prefiled testimony Dr. George Stolnitz, testifying on behalf of the Department of Energy, concluded that the appropriate ROE for the Company would be 11.45 percent. Although Dr. Stolnitz also relied upon DCF analysis, he was the only ROE witness who did not study the indicated return for a comparable group of companies. In fact, Dr. Stolnitz contended that DCF analysis should be specific to PSCo and urged the Commission not to consider any studies relating to other supposedly comparable companies. The reason for this recommendation was his view that there are a myriad of factors affecting a particular company's required return. Therefore, according to Dr. Stolnitz, the Commission cannot assume that investors in companies used for comparative purposes are truly representative of investors in PSCo. For this reason, Dr. Stolnitz's analysis relied wholly upon indicators specific to PSCo.

For the dividend yield component, Dr. Stolnitz used the average of the Company's 11 dividend yields from 1982-1992 with and without the April 1993 yield. The 11 dividend yields from 1982-1992 without the April 1993 measure, averaged 9.564 percent. Adding the April 1993 yield (6.7 percent) resulted in an average of 9.333 percent. For the growth component of his DCF model, Dr. Stolnitz utilized a projection from *Value Line* going out to 1995-1997. *Value Line* projected a 2.0 percent growth for PSCo for this time period. The calculated yields and the forecasted growth resulted in a ROE range of 11.333 to 11.564 percent. The average of this range is 11.45 percent, Dr. Stolnitz's point recommendation in prefiled testimony.

In his prefiled testimony, Dr. Stolnitz also commented that a ROE within 10.5 to 11.5 percent was supported by the Commission's ROE findings in a 1991 rate case involving the Company, modified by changes in capital markets since those findings were made. That is, he observed that the declines in interest rates since the 1991 decision would indicate a return within a range of 10.5 to 11.5 percent. Dr. Stolnitz updated his recommendation at hearing based upon this 10.5 to 11.5 percent range. Specifically, he stated that changes in the economy and in capital markets since his testimony was filed had caused him to select a return at the lower end of the range.[32] Based upon this reasoning, Dr. Stolnitz stated, at hearing, that his ROE recommendation was 10.7 percent.

{PRIVATE **}**Kenneth Eisdorfer (CII)**{**tc \l 3 "Kenneth Eisdorfer (CII)"**}**. Mr. Kenneth Eisdorfer testified on behalf of Colorado Industrial Intervenors. He concluded that PSCo's cost of equity is no more than 9.3 percent. This determination was based upon a DCF analysis of the Company and five comparison utilities.[33] For the growth component of his model, Mr. Eisdorfer used consensus estimates for anticipated growth in annual earnings over the next five years as reported by I/B/E/S. He determined

[32] The changes which caused him to lower his recommendation were: inflation and interest rates had declined even more since the filing of his testimony; national economic recovery remained slow; and interest rates and GDP growth were projected to be low in the future.

[33] One of the criteria Mr. Eisdorfer used in the selection of his comparison companies was that the utility must not have reduced dividends "recently." At hearing, he clarified that "recently" meant within the last four years. In fact, three of the five companies selected by Mr. Eisdorfer had reduced their dividend within the last 10 years.

the yield component for the group by dividing the currently effective annual dividend by the average closing price of the stock for the 30 trading days prior to the filing of his testimony. The resulting adjusted average cost of equity for the group was 9.59 percent (an unadjusted yield of 6.19 percent plus average growth of 3.3 percent). Mr. Eisdorfer performed the same analysis for the Company. That analysis produced a company-specific cost of equity of 8.25 percent (6.7 percent yield; growth rate of 1.5 percent).

Mr. Eisdorfer proceeded to present a CAPM study for the Company, utilizing the long-term treasury bond rate as of May 11, 1993. In this analysis, he determined the risk premium by averaging the difference in the returns on stocks and long-term government bonds for the 27 years 1966-1992.[34] This analysis indicated a cost of equity for the Company of 8.95 percent.

Based upon the average of the CAPM model and the group DCF results, Mr. Eisdorfer concluded that the Company's cost of equity was no greater than 9.3 percent. This recommendation would result in Company earnings of $1.79 per share, and would not allow the Company to maintain its current dividend ($2 per share). However, unlike Messrs. Ekland and Copeland, Mr. Eisdorfer did not make any

[34] This was the same data utilized by Dr. Avera in one of his risk premium models. However, Dr. Avera used the data for the entire reported period, 1926-1992.

adjustment in his recommended return to allow for additional interest coverage (Copeland), or to allow for maintenance of the current dividend (Ekland).

{PRIVATE **}**Ruling on Allowed Return on Equity**{**tc \l 2 "Ruling on Allowed Return on Equity"**}**. Based upon the evidence, we find that a fair and reasonable ROE is 11.00 percent. We reach this conclusion by first observing that the high and low recommendations of the witnesses are unsound. As pointed out by the Company, Mr. Eisdorfer's recommendation of 9.3 percent would result in earnings per share of $1.79, significantly lower that the Company's present dividend, and this would not preserve the financial integrity of PSCo. Cross-examination of Mr. Eisdorfer, as well as testimony offered by other witnesses (*e.g.*, rebuttal of Dr. Avera, page 5), makes clear the serious consequences of actions which would likely require the Company to reduce its dividend. For example, at the rate of return endorsed by Mr. Eisdorfer, potential consequences include precipitous declines in the Company's stock price and serious negative impacts on PSCo's preferred stock and debt securities. These results seriously could impact ratepayers by affecting the ability of the Company to maintain its quality of service or by significantly raising the Company's cost of capital. We conclude that Mr. Eisdorfer's recommendation is unreasonable and should not be approved.

We also conclude that the recommendations by Dr. Avera are unreasonably high and unfair to ratepayers in light of current conditions in capital markets. In part, we agree with much of the specific criticism of Dr. Avera's analysis made by the Intervenors. Objections to his analyses which we find to be credible include:

1. In arriving at his recommendation, Dr. Avera arbitrarily excluded all growth rates which he regarded as too low, based upon his assessment that the derived results were unrealistic as compared to interest rates for lower risk securities. Mr. Copeland pointed out that most of Dr. Avera's DCF results passed Dr. Avera's own test of reasonableness (*i.e.*, cost of equity estimates were above costs of debt), especially in light of current conditions in capital markets.

2. A cardinal assumption in Dr. Avera's risk premium analysis was the purported inverse relationship between interest rates and risk premiums. Mr. Copeland's testimony suggests that it is not axiomatic that risk premiums will always rise or fall inversely to changes in interest rates. The evidence suggests to us that Dr. Avera's assumption is not true at the present time.

3. Dr. Avera made specific adjustments to his results which were unjustified. One of these was an adjustment for flotation costs which was criticized by Multiple Intervenors witness James Selecky. In addition, at hearing, Dr. Avera conceded that his most recent analysis indicated that the range for ROE for the Company was 11.75 to 12.75 percent. Nevertheless, he adjusted the range upward by .25 percent to account for his belief that investors still perceive electric utilities as having some additional risks. The market already should have accounted for all risks.

4. Most importantly, we agree with the Intervenors that DCF results should not be ignored as suggested by Dr. Avera. As suggested by witnesses such as Messrs. Ekland and Copeland, there have been remarkable declines in the cost of capital in current markets. DCF analysis in this case is consistent with these current conditions. (We make this finding even though we acknowledge that DCF results should be tempered by other considerations.)

Generally, we conclude that the analyses of Messrs. Copeland and Ekland are superior to that of Dr. Avera and the other witnesses. Mr. Copeland's recommended range for ROE was 10.5 to 11.0 percent. Mr. Ekland suggested a range of 10.29 to 11.29 percent. We conclude that a ROE of 11.00 percent is fair and reasonable.[35] We believe this return gives the Company an adequate opportunity to sustain its dividend and to maintain its financial integrity. While this return may not assure the Company an improvement in its bond rating from BBB+ to A, it is, nonetheless, a sound return that gives management an adequate foundation from which to improve its rating from BBB+ to A. We

[35] Mr. Ekland suggested that the Commission should select a return which would cause the Company's market to book ratio to move toward 1 in the long run. We do not agree that this is an appropriate consideration in setting rate of return. Our determination of the proper ROE should be based upon the type of judgments reflected in this decision. The market will attend to the Company's market to book ratio according to its own considerations.

agree with Messrs. Copeland and Ekland that a higher return would be excessive and unfair to ratepayers.

{PRIVATE **}**Capital Structure and Composite Cost of Capital**{**tc \l 2 "Capital Structure and Composite Cost of Capital"**}**. Staff recommended that the Commission use the capital structure as of the end of the historical test year, adjusted by removing $13,931,013 which was added to the capital structure by PSCo witness Darnell. This amount represented the accumulated losses from the Company's nonregulated subsidiaries. The Company opposed this Staff adjustment, pointing out that the Commission's past policy has been to keep ratepayers neutral with respect to nonregulated subsidiary operations. Since the assets devoted to utility service are not affected by subsidiary operations, or are affected only indirectly and negligibly, the Company asserts the adjustment to capital structure proposed by Staff should be rejected.

We agree with the Company. The Colorado Supreme Court has held that, unless it is demonstrated by a substantial showing that ratepayers are materially prejudiced by the actual capital structure which finances utility operations, the Commission should use that actual utility capital structure in calculating rates. *Peoples Natural Gas v. Public Utilities Commission*, 567 P. 2d 377 (Colo. 1977). This is consistent with the Commission's policy of keeping ratepayers neutral with respect to subsidiary operations. The record in this case does not show that ratepayers will be prejudiced by use of the actual capital structure used to finance utility operations, as proposed by the Company.

Both the Company and the OCC recommended adoption of the actual utility capital structure as of the end of the historical test year.[36] We accept that recommendation. Therefore, the capital structure and the composite cost of capital is determined to be:

{PRIVATE **}**		Percent of Total	Cost	Wtd. Cost
Long-Term Debt	$980,950,000	46.57%	8.38%	3.90%
Preferred Stock	185,654,500	8.81%	6.65%	.59%
Common Equity	939,896,883	44.62%	11.00%	4.91%
Total	$2,106,501,383	100.00%		9.4%

{PRIVATE **}**INCOME STATEMENT**{**tc \l 1 "INCOME STATEMENT"**}**

The Commission's findings regarding operating expense and revenue adjustments are summarized in Attachment B to this Decision. The disputes between the parties regarding income

[36] In its future test year, PSCo utilized a projected capital structure. However, since we have rejected the future test year, all issues relating to the forecasted capital structure are moot.

statement issues and the Commission's decisions on those disputes are set forth in this section.

{PRIVATE **}**Full Tax Normalization and "Catch-Up" Provision**{**tc \l 2 "Full Tax Normalization and \"Catch-Up\" Provision"**}**

The Company, in this case, proposed to use full normalization as the method of accounting for income taxes on a going-forward basis. In addition, the Company proposed a "catch-up" provision for additional deferred taxes which would have accrued had full normalization been used during past periods of time. We now approve both proposals.

"Normalization" refers to the accrual accounting/ratemaking practice which reflects the income tax effects, including timing effects, of a transaction at the same time the related transaction is recorded on the regulated books of account.[37] "Full normalization" refers to the practice of providing deferred taxes on all book/tax timing, or temporary differences. As explained in the testimony, temporary differences are transactions which impact book income and taxable income in different periods. This issue arises because taxes are not always required to be paid by a utility at the same time the tax obligation is incurred. As stated by various witnesses, the debate centers around the

[37] In contrast, "flow-through" is the accounting method which, for ratemaking purposes, provides only for income tax expense payable currently as cost of service income tax expense for the period.

question of whether customers should be charged for those taxes at the time the tax obligation is incurred, or at the time the tax is actually paid. If customers are charged (in rates) at the time the tax obligation is incurred, the accounting is referred to as "normalization." If customers are charged only at the time the tax is paid, the accounting is referred to as "flow-through."

None of the parties objected to the Company's request to use full normalization prospectively. PSCo witness Jeter noted that full normalization is used by many regulatory commissions. In addition, Mr. Jeter testified regarding some of the benefits of the normalization method (*e.g.*, the method sends proper price signals and helps maintain the financial integrity of public utilities). No one disputed the Company's proposal, and we conclude that it should be approved.

In addition to using full normalization on a prospective basis, the Company also proposed the inclusion of a "catch-up" amount in rates. PSCo witness W. Wayne Brown testified that "the catch-up amount is the amount of additional accumulated deferred taxes that would be reflected in our [PSCo's] financial accounting records had we been on the full tax normalization method of accounting for income taxes . . . ." (Exhibit P, pp. 28-29). The Company calculated the catch-up amount as of July 1, 1993, as being $132,420,000. In this proceeding, the Company proposes to recover an annual amortization amount of $10,188,000 per year in cost of service to collect the catch-up amount on a straight-line basis over approximately 13 years. The Company selected 13 years as the amortization period in order to avoid the risk of violation of IRS rules regarding the minimum amount of tax normalization required for public utility property. That is, the amortization of the catch-up amount was designed to never allow the balance in the net accumulated deferred income tax account to drop below what it would have been if only the temporary differences addressed by the Internal Revenue Code were normalized.

Multiple Intervenors, through witness James Selecky, objected to the catch-up proposal. As grounds for his opposition, Mr. Selecky argued: (1) the catch-up provision would, as compared to continuing with the flow-through method, would "overcollect" by substantial amounts in the suggested 13-year amortization period; (2) the catch-up plan is not mandated by statute, rule, or any other legal provision; and (3) no compelling justification for the proposal was presented.

In general, we do not agree with these contentions. We note that Mr. Selecky is correct that the catch-up proposal is not legally mandated. For example, the Internal Revenue Code does not require that the catch-up suggestion be implemented. On the other hand, we disagree with the argument that there will be "overcollection" of monies from ratepayers under the catch-up proposal. Admittedly, ratepayers will pay more over the next 13 years under the Company's suggestion. However, the total amounts eventually collected from ratepayers under the catch-up proposal and the flow-through method are the same. The catch-up provision simply accelerates recovery over the next 13 years (as compared to continuing to collect from ratepayers for 30 years or longer).

We agree with the Company that one benefit of its proposal is to levelize payments for past flowed-through tax benefits. This "rate stabilization" for customers is preferable to the volatile recovery entailed in the flow-through method. Most importantly, we note that, with respect to these costs, ratepayers must "pay now, or pay later." Our rulings regarding the Company's overall revenue requirement in this proceeding--the Company's rates will remain stable, even with the catch-up provision--present an opportunity for recovery of the catch-up amounts without burdening customers. This circumstance may not present itself in the future, and deferring recovery of past tax obligations, as entailed in the flow-through method, may result in future hardship for ratepayers.

The Company also argued that the catch-up proposal results in "intergenerational equity" (*i.e.*, customers who received the "benefits" of past tax treatment practices would be more likely to pay under the catch-up method). We find that neither flow-through nor the catch-up proposal perfectly matches ratepayers with benefits. However, we conclude that the catch-up plan is superior with respect to matching, inasmuch as it results in faster recovery of past obligations without unduly burdening present customers.

{PRIVATE }New Load Annualization{tc \l 2 "New Load Annualization"}

In its historic test year filing, the Company proposed certain adjustments to test year sales to recognize the effect of customer additions and losses. The Company referred to this modification of the test year as the "New Load Annualization Adjustment." For its retail operation, PSCo's new load annualization adjustment resulted in a *pro forma* reduction to test year sales of 101,501,900 kwh. The Company made this adjustment to account for the loss of certain large commercial and industrial customers during the test year. According to the Company, these customer losses are "known and measurable"[38] and should be accounted for if the test period is to be representative of the future.

[38] the context of making *pro forma* adjustments, "known and measurable" refers to changes in a utility's financial operations which have occurred or are certain to occur where the impact of such changes are quantifiable (*e.g.*, a change in the tax rate).

OCC witness David Effron opposed this adjustment. Mr. Effron argued that this adjustment selectively recognizes load changes causing decreases in sales without recognizing factors tending to result in increased sales during the test year. Mr. Effron pointed out that commercial and industrial sales for the first five months following the end of the test year were greater than such sales during the first five months of the test period. The evidence also indicated that the total number of commercial and industrial customers actually has been increasing. Mr. Effron recommended that PSCo's new load annualization adjustment be eliminated and that test year commercial and industrial sales be increased by 101,501,900 kwh. According to Mr. Effron's calculation, such an adjustment would increase *pro forma* revenues by $4,278,000. Mr. Effron also attempted to recognize increased fuel expenses for the increased sales and therefore adjusted test year fuel expense by $1,441,000. The net effect of Mr. Effron's modifications is an increase of $2,837,000 to pre-tax operating income for the Company.

In rebuttal, Mr. Darnell disputed this calculation, claiming that Mr. Effron should have also adjusted variable production expense, but did not furnish a figure quantifying this adjustment. Mr. Darnell's prefiled rebuttal testimony [pages 16-20] pointed to the decision in I&S Docket No. 1640, as authority for the proposition that load changes should be counted. In fact, at page

57 of that decision, the Commission stated that it would not consider economic changes in loadsunless there were wide swings that would not likely be repeated. As noted by Mr. Effron, the net effect of changes in load decreases and increases is difficult to quantify accurately. In addition, the 101,501,900 kwh load reduction accounted for by PSCo cannot be characterized as a wide swing. Given PSCo's total load, the reduction equates to much less than 1 percent.

This proposed adjustment goes to the essence of test year integrity addressed earlier in this decision. A selective quantity adjustment such as this tends to distort the interrelationships that form the foundation of the test year concept. The test set forth in the decision in I&S Docket No. 1640 discussed parameters to this type of adjustment (*e.g.*, these would only be made in very unusual circumstances).

We conclude that the OCC's position on this issue is correct.[39] The Company's proposed modification to test year sales is selective. While the Company may not be able to identify specific customer additions, the available information nevertheless indicates that total commercial and industrial sales are not decreasing, and the adjustment is not supported by the

[39] In the absence of contrary financial information from the Company as to the effect of reversal of its new load annualization adjustment, we accept Mr. Effron's computations as reasonable.

magnitude of the claimed change. Since the Company's load annualization adjustment proposal relies expressly on the assumption of decreased sales, it should be rejected as recommended by Mr. Effron.

{PRIVATE **}**The Productivity Offset for Out-of-Period Wage Adjustments**{**tc \l 2 "The Productivity Offset for Out-of-Period Wage Adjustments"**}**

PSCo bases its request for additional revenues on a future test year, but it was also required to file an historic test year. This data was presented in Ronald N. Darnell's direct testimony and exhibits filed on May 5, 1993. Typically, in an historic test year, a *pro forma* adjustment is made for known and measurable, out-of-period wage increases. However, such an adjustment requires the inclusion of a productivity offset. PSCo abided by these conventions in its historic test year, using 2.97 percent as its productivity offset. This was derived by computing the weighted average of the compound growth rates of output per unit of labor in the Electric and Thermal Energy Departments (3.73 percent) and in the Gas Department (1.45 percent), using data from 1987 through 1991.

Staff witness Gary E. Schmitz offered two criticisms of PSCo's method of estimating the productivity offset. First, Dr. Schmitz noted that the result was sensitive to the time period chosen. Inclusion of one or both of the years 1986 and 1992 caused the growth rate for the same variable to rise substantially. For example, the productivity offset was 4.88 percent for 1986-1992 but 3.87 percent for 1987-1992. Using 1987-1991, as PSCo did, was to its advantage since a lower productivity offset implied a greater remaining net revenue adjustment which, in turn, implied the need for a greater increase in the revenue requirement. In 1986 and 1992, PSCo reduced its labor force considerably. According to Dr. Schmitz, these years should not necessarily be viewed as anomalies and excluded from these calculations because the Company may well engage in further labor force reductions as it continues to respond to competition in the future.

Second, Dr. Schmitz noted that the variable output per unit of labor did not really measure labor's contribution alone to productivity growth. Rather, it included growth in output contributed by all factors of production (*i.e.*, labor, capital, materials, etc.). Consequently, it overestimated labor's share in productivity growth. Dr. Schmitz suggested that multiple regression analysis is the proper method for separating labor's contribution to productivity growth from the contributions of other factors. However, he observed that such analysis has problems of its own, including deciding which variables to include, how to define and measure such variables and defining the time period from which data should be collected.

Finally, Dr. Schmitz noted that changing the time period would increase the estimate, and accounting for the contribution of non-labor inputs would decrease it. Because of the offsetting effects and the difficulties associated with executing a more rigorous analysis, Dr. Schmitz recommended using PSCo's original estimate of 2.97 percent.

The Commission agrees with the recommendation of PSCo and Staff that 2.97 percent be used as a reasonable estimate of the productivity offset. Staff's criticisms of PSCo's methodology are well taken. However, since the errors in measurement created by the Company's methodology have offsetting effects, we will not alter the original estimate. The Company should consider employing econometric estimation techniques in the future. Furthermore, labor force reductions may continue to be an important part of PSCo's operations and should not be discounted when productivity offsets are calculated.

{PRIVATE **}**In-Period Productivity Offset**{**tc \l 2 "In-Period Productivity Offset"**}**

Staff witness Frank Shafer proposed the inclusion of an offset for productivity for the in-period wage adjustment. The proposed adjustment reduced Operating and Maintenance expense by

$332,789 in the Electric Department, $169,094 in the Gas Department, and $3,230 in the Steam Department. The stated purpose for the adjustment was to comply with the Court's decision in *Colorado Municipal League v. Public Utilities Commission*, 687 P.2d 416 (Colo. 1984). According to Staff's interpretation of that decision, the Court mandated an adjustment to recognize increases in productivity during the test period when an adjustment is made to annualize changes in wage levels during that period.

We believe that interpretation is incorrect. We conclude that the Court's holding in *Colorado Municipal League* was that the Commission had failed to make adequate findings of fact in support of its decision regarding an in-period productivity offset. We do not believe that the Court mandated that such an adjustment be made in all cases.

Mr. Darnell (PSCo) testified in rebuttal that a productivity offset should not be applied against an in-period wage increase because such an offset would duplicate the productivity inherent in the test period. In addition, Mr. Darnell maintained that such an offset to an in-period wage increase would penalize the Company for achieving productivity gains, thereby eliminating any incentive for the Company to achieve labor productivity gains. We agree with these assertions.

This precise issue was also addressed in Decision No. R90-473, issued on April 2, 1990. We now reaffirm the findings made in that decision:

> [S]eparate productivity offset studies are not applied to in-period wage increases because a given test year already includes the various relationships between inputs and outputs of productivity as part of that test year. Thus, to utilize a given test year and also add a productivity offset to the wage and salary increases that had been annualized during that test year, would have the net effect of doubling the productivity offset, and thus work a penalty against the utility it was being applied to.

For these reasons, we refuse to adopt Staff's recommendation.

{PRIVATE **}**Advertising Expense**{**tc \l 2 "Advertising Expense"**}**

In its historical test year filing, the Company included advertising expenses totaling $2,442,000. These expenses were classified into five categories recognized in previous Commission decisions. The five categories are: (1) marketing and promotion; (2) community relations, image, and political; (3) energy conservation; (4) safety; and (5) customer programs and services messages. In prior proceedings, the Commission has allowed expenditures on advertising from categories 3, 4, and 5 into rates. Advertising expense related to categories 1 and 2 traditionally have been disallowed for ratemaking purposes. The standard against which advertising expenses are judged for allowance has been whether the ads have directly benefited ratepayers.

In this proceeding, the Company requested rate recovery for all advertising expenses, even those expenses incurred for ads in categories 1 and 2, *supra*. Company witness Stephen Volstad in testimony argued that advertising in the first two categories (*i.e.*, marketing and promotion messages and community relations, image, and political messages) is of real benefit to ratepayers, even if the benefits are indirect. In his rebuttal testimony (pages 1-13), Mr. Volstad testified:

> Advertising categorized as marketing and promotion, community relations or image is part of building a business relationship with our customers, either by discussing issues directly related to providing energy services, or else by discussing the broader role in the community that the Company plays. There are many direct or indirect benefits to our customers from this sort of communication. Some messages call customer attention to products and services that are environmentally beneficial, such as natural gas logs and fireplaces, the use of compressed natural gas as a vehicle fuel, or the opportunity to purchase trees at a discount through our "Plant a Better Future" program . . . . The messages which are strictly about the various ways we support worthwhile community programs let appropriate agencies and non-profit interests know that they might approach Public Service Company to support their own worthy activities that benefit the broader public. In addition, they bring more community attention to important issues, such as early childhood education and the needs of senior citizens. In communicating a corporate interest in these issues, we contribute to their solution by focusing increased public attention on them. This, too, benefits our customers.

Staff and the OCC urged the Commission to maintain its present policy of disallowing advertising expenses associated with marketing and promotion messages and community relations, image and political messages. These parties argued that only expenses directly beneficial to ratepayers should be included in rates. At the request of the Commission, the Company submitted into the record copies of all advertising for which rate recovery was sought (Exhibit 306). Staff witness Frank Shafer reviewed all ads and recommended disallowance of $1,825,853 for expenditures associated with advertising in the first two categories, *supra*. These recommended disallowances were set forth in Exhibits 331 and 332.

We reaffirm here previous Commission policy that only those advertising expenditures which are directly beneficial to ratepayers (as ratepayers) should be allowed into rates. We emphasize that customers of utility services have no choice in the rates they pay for utility offerings. That is, subscribers to utility services must pay the rates set by this Commission in order to receive service. We also note that, since utility offerings are crucial to most consumers, foregoing these services is not a realistic option. Inasmuch as customers have no choice in the rates to be paid for critical services, it is important that only those expenses directly related to the provision of such services be included in the regulated cost of service. We believe that our previously enunciated standard for allowance of advertising expenses in rates--that the expenses be of <u>direct</u> benefit to ratepayers--serves this purpose. Therefore, we accept Mr. Shafer's recommendations and reject the Company's suggestion that our previous policy be modified. We believe categories 3, 4, and 5 are of direct benefit to ratepayers, and costs for ads properly includable in those categories are appropriate ratemaking expenses.

<u>**{**PRIVATE **}**Education Contributions**{**tc \l 2 "Education Contributions"**}**</u>

In this docket, the Company proposed recovery of contributions made in support of education. The Company stated its belief that such contributions are consistent with a recent resolution adopted by the National Association of Regulatory Utility Commissioners ("NARUC"). In addition, Company witnesses maintained that contributions in support of education are beneficial to ratepayers. Benefits to ratepayers, according to this testimony, include: (1) a better educated workforce from which all businesses, including PSCo, may draw; (2) improvements in the education process for the children of many of the Company's customers; and (3) improvements in the quality of life in the Company's service territory.

Both Staff and the OCC objected to inclusion of these costs in rates. Although both of these parties agreed that contributions in support of education are commendable and demonstrate good corporate citizenship on the part of the Company, each party concluded that these expenses are not properly included in cost of service. Staff witness Shafer argued for disallowance of these expenditures on the grounds that "they do not have a direct benefit to the ratepayer." OCC witness Effron reasoned that such costs "are not necessary for the provision of utility service" and are "discretionary expenditures on the part of the Company." Mr. Effron characterized these expenditures as charitable contributions.

We agree with Staff and the OCC, and rule that these costs may not be allowed in rates. So that the matter is clear, we acknowledge the critical importance of education to all residents of the State. We also congratulate the Company for its support of such a deserving cause. However, as with expenses related to advertising and charitable contributions, we note that inclusion of such costs in rates would entail <u>involuntary</u> contributions on the part of ratepayers in support of a cause not directly related to the provision of utility service. While we agree with the Company that local education is worthy of financial support, we are unable to conclude that all ratepayers share the same belief and that such expenditures benefit ratepayers <u>as</u> ratepayers. It is for this reason that we distinguish between expenditures which are necessary to the provision of service from those which are not. Therefore, we accept Staff's and OCC's reduction of the Company's *pro forma* test year electric operation and maintenance expenses by $613,000 and the reduction of *pro forma* test year gas operation and maintenance expenses by $259,000. This is not to say that all such expenditures will be treated this way in the future. Expenditures which can be shown to result in more benefit to ratepayers than to the general public potentially may be included in cost of service.

{PRIVATE **}**American Gas Association Dues**{**tc \l 2 "American Gas Association Dues"**}**

In March 1992, the Committee on Utility Association Oversight of NARUC released the 1990 Report on the expenditures of the American Gas Association ("AGA"). Based upon that report, Staff witness Billy Kwan determined that at least 46.71 percent of the AGA's expenses went to certain advertising (marketing and promotion, community relations, and image) and lobbying purposes which this Commission historically has disallowed for ratemaking. Mr. Kwan, in his testimony, listed the specific expense categories of AGA dues which he found to be objectionable. We accept Staff's recommendation.

As noted in the discussion in this decision regarding advertising and education expenses, the Commission's policy has been to disallow, for ratemaking purposes, certain advertising and political expenditures. Mr. Kwan's recommendation is consistent with the policy articulated and will be adopted.

{PRIVATE **}**Westgas Supply Company Merger Savings**{**tc \l 2 "Westgas Supply Company Merger Savings"**}**

In Docket No. 92A-352G, PSCo applied for Commission approval to merge the assets of Western Gas Supply Company ("WestGas") into the Company.[40] The Commission approved the application for merger, and it became effective on January 1, 1993. The Company supported its request for approval of the merger application in Docket No. 92A-352G, in part, by asserting that the merger would result in more efficient operations and increased productivity. Based upon the Company's representations, an Administrative Law Judge for the Commission approved the application finding that "[t]he synergies created by the merger include but are not limited to, the elimination of duplicate functions, parallel management, and direct labor savings of approximately $950,000 annually." *See* Decision No. R92-1526, at 3. In the present filing, the Company proposed a *pro forma* adjustment which reflected WestGas merger savings of $524,418 instead of the savings of $950,000 originally projected in Docket No. 92A-352G.

Staff contended that the Company should be held to the

[40] WestGas was an affiliate of the Company. Its market included making gas sales for resale to customers such as Greeley Gas Company and PSCo, which are natural gas distribution utilities.

estimated savings from the merger docket, and proposed an additional adjustment of $425,582 as a reduction to Administrative and General Expense. In Staff's view, the estimated $950,000 in savings was meant to represent the minimum efficiencies which would result from the merger. Consequently, Staff disputed the Company's *pro forma* adjustment for merger savings as being insufficient.

We find that the Company's proposed adjustment should be accepted. As Company witness Fredric Stoffel noted, the $950,000 estimate of savings was made in July 1992, and was based upon the best information available at that time. Subsequent estimates based on experience following the merger indicated that merger efficiencies were less than projected in Docket No. 92A-352G. We emphasize that the Company's revised estimates of savings still show ratepayer benefits resulting from the merger. No evidence was presented that the Company's current savings estimate is inaccurate. Instead, Staff's position is simply that the Company should be bound to a projection made at the time the merger was approved. We disagree.

We believe that all parties and the Commission, in Docket No. 92A-352G, understood that the $950,000 projection of savings was merely an estimate, not a guarantee. Notably, a savings of $524,418 instead of $950,000, would have been sufficient to justify approval of the merger application. Since the best evidence of record in this proceeding indicates that $524,418 is the actual test year ratepayer benefit from the merger, that is the amount which should be accepted for ratemaking purposes here.

{PRIVATE }Off-System Sales{tc \l 2 "Off-System Sales"}

For the historic test year, the Company made an adjustment to revenues in order to flow through to ratepayers the benefit of additional revenues from off-system sales not previously credited through the ECA. OCC witness David Peterson pointed out that in Docket No. 91A-587EG, the Colorado-Ute acquisition proceeding, Company witnesses testified that the purchase of Ute's generation and transmission facilities would allow PSCo to enter new wholesale markets for the sale of electricity. In that docket, the Company provided planning and feasibility studies showing that, following the acquisition, the Company was anticipating off-system sales far in excess of those included in the historical test year.[41] Mr. Peterson recommended that the historical test year revenues be increased to reflect an annualization of off-system sales following the purchase of Colorado-Ute's assets.

Company witness William J. Martin pointed out that the details of the Ute acquisition changed over time. For example,

[41] The Company has claimed that the specific cost, sales, and revenue information is confidential, and, therefore, that information was filed under seal.

Mr. Martin noted that the Company originally projected a positive $10 million acquisition adjustment. *See*, discussion, *supra*. In fact, Ute's assets were acquired for $5.9 million less than book costs, resulting in a negative acquisition adjustment for that amount. The Company maintains that the difference between off-system sales projections and those which actually have occurred is indicative of the many factors relating to the Ute transaction which changed during and after the acquisition process. Mr. Martin suggested that if the Company is to be held to its off-system sales projections, it also should be held to its projected acquisition adjustment.

We find that the Company's position on this matter is the correct one. In particular, we conclude that the Company should not be penalized in these circumstances for its reasonable projections which eventually prove to be somewhat inaccurate. Furthermore, since we have ruled that the historical test year will be utilized in this docket, we believe that actual off-system sales during the test period should be used for ratemaking purposes. We, therefore, reject the OCC's proposed adjustment.

{PRIVATE **}**Change in Income Tax Rate**{**tc \l 2 "Change in Income Tax Rate"**}**

In rebuttal, PSCo witness Richard Kelly, while addressing the question of attrition and responding specifically to the matter raised by Staff witness Ekland, pointed out that effective January 1, 1993 the federal corporate income tax rate increased from 34 to 35 percent for earnings in excess of $10 million. According to the Company's unrebutted analysis of the new tax law, there are no material offsetting provisions which would tend to decrease the Company's tax expenses. This change in the corporate tax rate is a "known and measurable" change to the Company's operations. Since the increase in the tax rate is effective a scarce three months after the end of the historical test year, it is appropriate to make a *pro forma* adjustment for the increase in the Company's cost of service in this proceeding. We now find that the Company's revenue requirement test year tax expense should be increased to account for the change in the federal corporate income tax rate in accordance with Attachment B.

{PRIVATE **}**GENERAL ISSUES**{**tc \l 1 "GENERAL ISSUES"**}**

{PRIVATE **}**Elimination of the Electric Cost Adjustment**{**tc \l 2 "Elimination of the Electric Cost Adjustment"**}**

The ECA compensates the Company for the difference between actual fuel costs in a given month and the fuel costs included in base rates in the last rate case. OCC witness Robert Hix outlined the advantages and disadvantages of an ECA. Advantages include reduction in regulatory lag, ease of administration, avoidance of rate shock, and timeliness of price signals. On the other hand, according to Mr. Hix, disadvantages exist, including increased ratepayer risk, reduced incentives for the utility to increase efficiency in the fuel area, distortions of management decisions, and reduced incentives for the utility to bargain hard for purchased power and fuel supplies.

Mr. Hix recommended that PSCo's ECA be eliminated because of the disadvantages of ECAs in general, and because two of the important conditions which led to the adoption of the ECA in the mid-1970s no longer exist. These conditions were: (1) highly volatile fuel prices and; (2) recognition that these prices were beyond the control of the utility. In addition to recommending elimination of the ECA, Mr. Hix recommended that the Company be required to continue to report fuel costs for informational purposes and suggested that some substitute mechanism, neutral with respect to management decisions, could be developed to cope with unusual circumstances. Mr. Hix contended that as a last resort, an ECA could be reinstated if necessary. Finally, Mr. Hix suggested that the Company was attempting to change the structure of the ECA cost determination by replacing "total energy costs" with "projected energy costs." Such a change would make these costs forward looking, according to Mr. Hix, and would violate the revised settlement agreement on the ECA entered into by the Staff, OCC, and PSCo on May 27, 1992 in Docket No. 91A-480EG. During the hearing, Mr. Hix agreed with PSCo that projected energy costs do not have these deficiencies, but recommended that the word "projected" be deleted from the energy cost term.

James Gilliam of PSCo argued that Mr. Hix's method of computing fuel costs smoothed out much of the volatility that still remains and, if done properly, would lead to the conclusion that conditions have not changed enough to warrant elimination of the ECA. Furthermore, he argued that conditions have changed little since 1992 when the OCC willingly signed the revised settlement agreement which indicated that the restructured ECA would go into effect at the conclusion of Phase I of this rate case. Finally, concerning PSCo's use of "projected energy costs," Mr. Gilliam cited the definition of this term from the proposed tariff sheets in his rebuttal testimony and indicated that it is neither forward looking nor violative of the revised settlement agreement.[42]

Although the Commission finds that it is not precluded from

[42] The Commission agrees with PSCo that the term "Projected Energy Cost" defined on the 147th Revised Sheet No. 55A of its proposed tariff is neither forward looking nor contrary to the provisions of the revised ECA settlement agreement dated May 27, 1992, in Docket No. 91A-480EG. On the other hand, the Commission supports OCC's observation that the word "projected" is misleading and so orders the definition changed to read as follows:

> The Energy Cost will be equal to the Actual Energy Cost for the previous twelve month period ending June 30, divided by the total kilowatt-hour sales for the same period, with appropriate adjustments.

Similarly, all other references to "Projected Energy Cost" should be replaced by "Energy Cost."

eliminating the Company's ECA by virtue of having approved in Docket No. 91A-480EG the revised settlement agreement dated May 27, 1992, it will reject OCC's recommendation. We find that the record is insufficient to support such a major change in policy at this time. Nevertheless, we observe that there may be a number of disadvantages with ECAs in general and that current conditions in fuel prices may render ECAs less imperative now than in the 1970s when they were first established. For these reasons, the Commission will open a rulemaking docket in which the ECAs of all Colorado jurisdictional utilities will be re-evaluated. This process should take into account the different characteristics of various utilities and the different circumstances in which they find themselves. For each utility, the result of the rulemaking process could be: (1) retention of its existing ECA, (2) reconstruction of the ECA, or (3) its complete elimination.

{PRIVATE **}**Modifications to Gas Cost Adjustment[1]**{**tc \l 2 "Modifications to Gas Cost Adjustment[43]"**}**

The Company and OCC proposed various modifications to the Gas Cost Adjustment ("GCA"). The Company initially suggested that the Gas Research Institute ("GRI") charge and shrink expense and liquid product revenues be included in the GCA.[44] Presently, each

[43] The GCA is procedure included in the tariffs of the Company that allows the pass-through to customers of certain increases and decreases in the cost of gas.

[44] The GRI charge represents the charges from the Company's natural gas pipeline suppliers subject to Federal Energy Regulatory Commission ("FERC")

of these items is accounted for in base rates. After the OCC and Staff objected to inclusion of these items in the GCA, the Company agreed in rebuttal that recovery of GRI charges and shrink expenses (with the offset for liquid product revenues) should continue to be recovered in base rates. The Company suggested that all issues related to the GCA should be deferred to generic proceedings in Case No. 5721-Reopened. The Company agreed with the OCC that the Commission should conduct an investigation of the GCA. Furthermore, the Company contended that the investigation should be applicable to all jurisdictional gas utilities, not only PSCo. In any event, the Company has withdrawn its initial proposal to include GRI charges, shrink expense and liquid product revenues in the GCA. The Company's decision to withdraw its original requests relating to the GCA is approved. These issues will be investigated in a generic or rulemaking proceeding, as the Company recommended.

Currently, the Company collects the FERC Annual Charge Adjustment ("ACA")[45] in the GCA. OCC witness Robert Hix proposed that the ACA charge be excluded from the GCA. We reject this

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regulation. Such charges are billed to the Company under FERC-approved rates.

"Shrink expense" is the cost associated with the processing of natural gas from the wellhead to remove a variety of liquid products. "Liquid products revenues" are the revenues from the sale of the products removed during the extraction process.

[45] The ACA charge is designed to recover FERC's operating costs. The Company pays these charges to its interstate pipeline suppliers.

suggestion at this time. As stated above, we agree with the Company that all issues relating to the GCA should be explored in a separate proceeding. For the present, we conclude that no change should be made to the GCA.

Next, the OCC recommended that take-or-pay ("ToP") costs be excluded from recovery in the GCA. In Decision No. C89-1419, the Commission announced its policy with respect to recovery of ToP costs. In that decision, the Commission held that FERC-approved ToP costs were presumed to be reasonable expenses which may be passed through to customers through the GCA. In light of that previous determination, we agree with the Company that a significant change to this policy should be fully investigated in a separate proceeding. Mr. Hix acknowledged that these issues are complicated and controversial. Therefore, we conclude that it would be inappropriate to accept the OCC's proposal in this forum. Moreover, we note that the OCC did not propose a specific adjustment to base rates to give the Company an opportunity to recover these costs. Consequently, the evidence is insufficient to accept this proposal in this case.

As noted, *supra*, the Commission approved the merger of WestGas with PSCo in Docket No. 92A-252G. That merger contemplated that a common GCA be implemented for all merchant gas sales. The Company included a proposed common GCA as one of its proposals in this case. No party objected to this suggestion, and it will be approved.

<u>**{**PRIVATE **}**Proposed Future Proceedings**{**tc \l 2 "Proposed Future Proceedings"**}**</u>

The OCC recommended that the Commission order the Company to file rate cases on a regular three-year schedule. The Company opposed this suggestion pointing out that this proposal is unnecessary. The Company noted that there may be times when it needs to file rate cases more or less frequently than every three years. We concur with the Company's response. An order requiring the filing of a rate case every three years, even when there is no economic need to do so, would result in a substantial waste of resources on the part of all parties and the Commission.

We also note that rate cases may be initiated by entities other than the Company. For example, in previous decisions the Commission has held that the OCC has the legal authority to file complaints challenging a utility's rates and earnings. In addition, the Commission itself may initiate proceedings when it believes that rates may be inappropriate. We also note that the Company files an annual report (*i.e.*, an Appendix A report) with the Commission regarding its financial status. This report allows the Commission and interested parties to monitor the Company's earnings. In light of these circumstances, the OCC's suggestion should not be adopted.[46]

The OCC also recommended that the Commission establish a docket to investigate its jurisdiction over natural gas gathering facilities and activities. The question of the Commission's regulatory authority over natural gas gathering is beyond the scope of this proceeding. Additionally, we find that the evidence in this proceeding was insufficient to convince us of the necessity for such a new docket at this time. Therefore, the OCC's request is refused at this time. However, as the OCC is aware, it may file an appropriate pleading to pursue its concerns outside the present case. We take no position on the validity of such a potential pleading in this decision.

{PRIVATE **}**Interim Gas Riders**{**tc \l 2 "Interim Gas Riders"**}**

In this case the Company proposed two gas riders that would remain in effect until the conclusion of Phase II when new base rates would be established. One of these proposed riders (adjusted for historical test year base revenues) was a 4.70 percent increase applicable to PSCo's gas tariff base sales rates (exclusive of transportation tariff base rates). This rider is intended to recover the WestGas system costs currently included in

[46] The parties did not address the legal authority of the Commission to order a utility to file a rate case. Presumably, by this suggestion, the OCC intended that the Company be ordered to initiate rate proceedings and assume the burden of proof. Any party making such a recommendation in the future should discuss the legality of such an order.

gas charges to PSCo. No party opposed this rider. As a result of the Company merger with WestGas, this rider is appropriate and will be approved.

The second rider proposed by the Company was a Phase I rider to implement the revenue requirement determinations made in this proceeding. Notably, the Company proposed that this interim rider be applicable only to sales customers (*i.e.*, exempting transportation rates). The Company's proposal to exempt transportation services from the rates imposed by the Phase I rider, whether positive or negative, was supported unanimously by Intervenors who are PSCo transportation customers, such as Climax Molybdenum Company, Vesgas Company, Western Natural Gas and Transmission Corp., WestPlains Energy, and Greeley Gas Company. Staff and the OCC opposed this suggestion, contending that any Phase I rider should apply equally to all gas customers.

Those parties favoring exemption of transportation argued three points: (1) application of the Phase I rider would violate settlements made and approved by the Commission in previous dockets; (2) no cost-of-service study supported application of the rider to transportation rates; and (3) an interim rider at the level requested by the Company would have deleterious financial effects on transportation customers. We disagree with all three contentions.[47]

We emphasize that it has generally been the Commission's policy to impose Phase I riders upon all customers uniformly, pending completion of Phase II proceedings. The reason for this is obvious: A utility is entitled to begin collection of its newly set revenue requirement at the conclusion of Phase I. However, until cost allocation and rate design determinations are completed in Phase II, the Commission lacks evidence to differentiate between classes of customers for ratemaking purposes. Uniform surcharges at the completion of Phase I are the practical effect of the inability to draw rational cost and rate distinctions between customer classes until completion of Phase II. Without such rational distinctions, differential rates are unjustified.

In light of existing policy and the sound reasons underlying that policy, the absence of a cost-of-service study regarding transportation service and the potentially harmful rate impact of a Phase I rider on transportation customers, do not constitute valid grounds for the proposed exemption. Actually, the very same arguments can be advanced on behalf of sales customers. That is, no current cost-of-service study was introduced into the record indicating that sales customers' rates should be increased.

[47] Given our overall revenue requirement determinations in this decision which do not impose a rate increase, it is likely that the concerns raised by transportation customers in this dispute are more academic than real.

Additionally, an equitably uniform surcharge should have the same <u>relative</u> impact on sales as on transportation customers. No evidence was presented on the record in the present proceeding supporting a different result.

As noted above, the Intervenors who supported the transportation exemption argued that the settlement agreements in Docket Nos. 91S-552G and 91S-553G, the "Transportation Dockets," preclude application of the Phase I rider to transportation service. These Intervenors argued that the parties negotiated agreements in those two dockets in which transportation rates were established based upon a margin rather than a cost-based approach. In return for their agreement to pay margin-based rates to PSCo, the Company agreed that the negotiated rates would remain in effect until the conclusion of Phase II. Staff and the OCC strongly disputed this interpretation of the stipulations in Dockets Nos. 91S-552G and 91S-553G.

We reject this final argument in support of the transportation exemption. In the first place, it is unclear that the parties intended to preclude application of a Phase I rider to transportation. In fact, the relevant language from Docket No. 91S-553G states:

> The parties also agree that Public Service or any other party is free to raise cost allocation and rate design issues regarding gas transportation service on Public Service's system in Public Service's next rate case to be filed on November 2, 1992. As such, the parties

believe that the settlement rates set forth herein are acceptable on an interim basis.

The Commission observes that if the parties specifically intended to exempt transportation from the Phase I rider, this was not expressly stated. Testimony regarding the intent of the parties was offered. However, we note that neither the Commission, in approving the settlement agreements, nor any interested person reviewing the stipulations was notified of these interpretations.

Staff also pointed out that in a later case, Docket No. 92A-352G, all parties from the Transportation Dockets participated and agreed that one issue to be determined in Phase I of the rate case was whether any of the Phase I riders should apply to transportation rates. Paragraph 24 of the stipulation in Docket No. 92A-352G further provided that "all issues relating to riders shall be determined as part of Phase I of the rate case."

Therefore, we disagree with the parties who asserted that the settlements previously negotiated between parties and approved by this Commission in the Transportation Dockets exempted transportation rates from the Phase I rider. The Phase I rider should be applied uniformly to all customers of PSCo including transportation customers.[48]

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[48] In light of our interpretation of the agreements made and approved in Docket Nos. 91S-552G, 91S-553G, and 92A-352G, we need not address the authority of the Commission to modify previously approved settlements. For example, we

{PRIVATE **}**Effects of PSCo's Activities on Competing Businesses**{**tc \l 2 "Effects of PSCo's Activities on Competing Businesses"**}**

The Colorado Business Alliance for Cooperative Utility Practices (CBA) is a membership organization consisting of numerous companies and individuals throughout Colorado. Many of the CBA members face direct competition from the Company's non-utility programs, including: power quality programs; maintenance service; appliance repair; electric contracting; and demand side management activities. The CBA urged that PSCo has an unfair competitive advantage. The CBA contends that non-utility program costs are being recovered improperly from ratepayers, and that ratepayers improperly are being required to subsidize the Company's non-utility endeavors. Such practice is detrimental to both ratepayers and the business competitors of PSCo. The CBA made two recommendations addressing this cross-subsidization issue:

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do not rule here on the propriety of applying a stipulation among parties regarding future rates in a future docket, especially against parties in the future proceedings who were not parties to the stipulation.

1. An appropriate portion of relevant costs should be assigned to the non-utility programs and put below the line so that they are not recovered in utility rates. Relevant costs include direct and indirect costs, with indirect costs being allocated according to a fully distributed cost methodology. Moreover, the Company should charge these non-utility programs the market price for all services provided by the regulated utility portion of PSCo to these programs.

2. Any portion of energy conservation advertising which relates to the Ideal Energy Home Logo and marketing program should be disallowed since these efforts are promotions of non-utility programs.

The Staff and OCC agree that subsidization of non-utility programs by utility ratepayers should be prohibited. Staff proposed removal of the direct costs of PSCo's appliance repair program for that reason. It also was acknowledged that similar treatment would be appropriate for PSCo's power quality programs.

Earl McLaughlin argued on behalf of the Company that these nonregulated programs should be treated as above-the-line utility services, inasmuch as utility customers want PSCo to provide them. The Company, in turn, is responding to these requests and providing its utility customers with the energy service options they desire in order to develop and maintain good relationships with these customers. Mr. McLaughlin contended that the Company is not attempting to achieve a dominant market position in these nonregulated programs, nor does it act in anticompetitive ways. For example, with respect to appliance repair, PSCo currently only has a 5 percent market share, which has not significantly increased from year to year. Additionally, Mr. McLaughlin emphasized that the Company tends to set its prices for appliance repair in the top quarter of its competitors' range of prices. When a potential repair customer calls PSCo, service options are provided to the customer which include using the Company's services or contacting its competitors. Customers must hang up and make another call even if they want to use PSCo services. Therefore, the options are equally accessible. Mr. McLaughlin further noted that the Company also uses third-party providers in demand side management programs whenever possible.

Stephen Volstad of PSCo contended that the Ideal Energy Home program is designed so that residential customers can acquire information about energy use, and that this effort would not be complete without a discussion of energy efficiency and conservation. Consequently, he urged that these latter considerations cannot be separated from the rest of the program, and that all related expenses should be placed above the line.

PSCo and the CBA signed a stipulation (Exhibit 336) on September 28, 1993, regarding evidence relating to gas and electric appliance repair, the Ideal Energy Home residential marketing program, Power Quality Services, and the Surge Arrester program. The stipulation provided profit and loss statements for these programs for the historic test year ending September 30, 1992, which reflected incremental costs only. The parties also stipulated that PSCo used the same cost methodology in its future test year as in its historic test year, and that the use of gas and electricity by PSCo's appliance repair program was valued at variable costs, not at tariffed rates.

The Company's Appliance Repair, Power Quality, and Surge Arrester programs are not utility services and should not be included in the determination of the Company's revenue requirement in this docket. These nonregulated services should be treated in a manner analogous to deregulated telecommunications services in order to avoid cross-subsidization, as required by section 40-3-114, C.R.S. *See* sections 40-15-401, and 40-15-106, C.R.S. A fully distributed cost methodology should be used to assign direct and indirect costs to these nonregulated services. In rate cases, the revenue requirement will be determined for regulated services only.

Since such a methodology does not currently exist, nor was one offered in this docket,[49] the directly-assignable costs and

[49] It is our understanding that such a cost study has not yet been performed by the Company.

revenues of the Appliance Repair program identified by Staff witness Shafer and similar costs and revenues for the Power Quality and Surge Arrester programs stipulated to by PSCo and the CBA shall be removed from the historic test year revenue requirement. In addition, in order to have such a fully distributed cost methodology for future use, PSCo shall develop such a methodology and present it in a proceeding involving small business issues related to the National Energy Policy Act of 1992. This issue is to be included in Docket No. 93I-098E, PSCo's Integrated Resource Plan. In developing this methodology, consideration should be given to the proper procedure for imputing a charge for use of regulated services by nonregulated programs and to the clear, detailed delineation of costs and revenues for nonregulated programs.

{PRIVATE **}**PHASE II**{**tc \l 1 "PHASE II"**}**

{PRIVATE **}**Phase II Matters**{**tc \l 2 "Phase II Matters"**}**

The Company proposed to file its Phase II case based upon principles established in this proceeding. Mr. Gilliam emphasized that the Phase II filing may indicate a different revenue level than that authorized in Phase I. Staff, through Mr. Kwan, opposed this suggestion, and urged that the same test year be used for both phases of the case. Mr. Kwan argued that Staff and Intervenors have expended much effort examining and auditing the accounting information for the Phase I historical test year, and that use of a new test year for Phase II will force the parties to duplicate efforts made in this proceeding.

The Commission orders the Company to base its Phase II filing on the same test year approved in this decision (*i.e.*, year ending September 30, 1992). We agree with Mr. Kwan that changing the test year for Phase II would likely result in relitigation of issues decided in Phase I of this case. We agree with Staff that no sufficient reason for using a different test year for Phase II was presented.

The Company also proposed to implement interdepartmental sales rates in this case. Interdepartmental sales are the utility services provided by one department within the utility to another (*e.g.*, Gas Department sales to the Electric Department). Historically, the rates for use of interdepartmental services have been based upon variable costs only. The Company suggested that, as the utility business becomes more competitive, it becomes more important that each department within the utility reflect the true costs of doing business. Therefore, the Company proposed that each department should be treated as a stand-alone business and be required to "pay" the rates on file with the Commission for services obtained from distinct utility departments.

No party opposed this proposal. However, Staff witness Kwan suggested that the Commission also require the Company to carefully document discounting on gas transportation rates to other departments. This information would be important in cases of complaints from other transportation customers.

Staff also suggested that the Company's line extension policies should apply to interdepartmental services. Staff recommended that its proposed modifications, and the Company's, should be addressed in Phase II.

The Commission finds that these issues should be taken up and fully investigated in Phase II. Therefore, we do not approve the Company's proposal to implement interdepartmental sales rates or Staff's proposed modifications to that proposal at this time. The parties should resubmit these and related issues in Phase II.

{PRIVATE **}**CONCLUSION**{**tc \l 1 "CONCLUSION"**}**

The parties to this proceeding have raised numerous issues. A number of adjustments essentially were unopposed. These are adopted as reflected in Attachment B. To the extent this Decision does not specifically address an issue, the Commission now states that the particular treatment advanced with respect thereto by one or more parties does not merit adoption in this docket. Having found that PSCo's revenues should be decreased, we conclude that the proposed tariffs filed by the Company on January 20, 1993, by

Advice Letters Nos. 1192-Electric, 477-Gas, and 53-Steam should be suspended permanently. We further conclude that the revenue decrease found to be just and reasonable herein should be implemented by a uniform percentage decrease to rates presently in effect. We further conclude that, except as specified herein, this Decision will be a final decision subject to the provision of sections 40-6-114 and 40-6-115, C.R.S. Finally, we conclude that this Docket should be closed, and that PSCo should be required to file tariffs for a new Phase II docket to examine rate design issues as a result of the revenue requirement we have established in this Docket.

THEREFORE, THE **{**PRIVATE **}**COMMISSION ORDER**{**tc \l 1 "COMMISSION ORDER"**}**S THAT:

1. The tariff sheets filed by Public Service Company of Colorado pursuant to Advice Letter No. 1192-Electric dated January 20, 1993, hereby are permanently suspended.

2. The tariff sheets filed by Public Service Company of Colorado pursuant to Advice Letter No. 477-Gas dated January 20, 1993 hereby are permanently suspended.

3. The tariff sheets filed by Public Service Company of Colorado pursuant to Advice Letter No. 53-Steam dated January 20,

1993 hereby are permanently suspended.

4. Public Service Company of Colorado hereby is directed to file by November 30, 1993, appropriate tariff sheets to reflect a General Rate Schedule Adjustment in the amount of 2.79 percent applicable to all electric base rate schedules. This General Rate Schedule Adjustment shall be filed to become effective upon one day's notice.

5. Public Service Company of Colorado hereby is directed to file by November 30, 1993, appropriate tariff sheets to reflect a General Rate Schedule Adjustment in the amount of 4.12 percent applicable to all gas base rate schedules, including transportation base rates. This General Rate Schedule Adjustment shall be filed to become effective upon one day's notice.

6. Public Service Company of Colorado hereby is directed to file by November 30, 1993, appropriate tariff sheets to reflect a General Rate Schedule Adjustment in the amount of 3.11 percent applicable to all steam base rates. This General Rate Schedule Adjustment shall be filed to become effective upon one days' notice.

7. Public Service Company of Colorado's proposal to remove existing gas and electric riders is approved.

8. Public Service Company of Colorado's request to establish a common Gas Cost Adjustment for the Company and Western Gas Supply Company is approved.

9. The settlement agreements of the parties reflected in Exhibits 250, 251, and 329 are approved.

10. The Motion to Strike by the Colorado Office of Consumer Counsel is denied, except as specifically stated in this Decision.

11. The Motion for Leave to File Statement of Position One Day Out of Time filed on September 30, 1993 by WestPlains Energy is granted.

12. All other motions pending hereby are denied.

13. On or before December 10, 1993, Public Service Company of Colorado shall file tariffs and a proposed procedural schedule for Phase II proceedings. That proposed schedule shall suggest prefiling dates for all testimony, suggested dates for hearings, suggested provisions for discovery, and other relevant matters. Copies of the proposed procedural schedule shall be served upon all parties to this Docket. Interested parties may respond to the Company's proposed Phase II schedule within 14 days of its filing

with the Commission.

14. This Decision and Order shall be considered a final decision subject to the provisions of sections 40-6-114 and 40-6-115, C.R.S.

15. The 20-day time period provided for in section 40-6-114(1), C.R.S., within which to file applications for rehearing, reargument, or reconsideration begins on the first day following the mailing or serving of this Decision.

This order is effective upon its mailed date.

ADOPTED IN SPECIAL OPEN MEETING October 14, 1993.

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

Commissioners

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