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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

	)	Docket No. 99-035-10
In the Matter of the Application of	)	
PacifiCorp for Approval of its	)	POST-HEARING MEMORANDUM
Proposed Electric Rate Schedules	)	OF THE COMMITTEE OF
and Electric Service Regulations	)	CONSUMER SERVICES
	)	
	)	

April 28, 2000

The Committee of Consumer Services (the “Committee”) submits this memorandum following the hearings in this matter. Partially in recognition of the fact that a joint narrative exhibit has been prepared dealing with all revenue, expense and rate base issues in this case, not all issues will be addressed in this memorandum.

CONTEXT

This case used a 1998 test year. That is the same year in which PacifiCorp (or the “Company”) admittedly neglected its management responsibilities. This Commission has heard, in this case and in the ScottishPower merger hearings, Company officers admit that management was “distracted” by its various global pursuits, and that it was not focused on controlling costs and taking care of its core electric business. One result of that was the ScottishPower merger itself. Other results are costs that were higher than they should have been, as discussed below. The Committee urges the Commission to keep this context in mind when examining this case. Certain adjustments need to be made as a result of management inattention over a period of time; ratepayers should not be forced to have such costs put into going-forward rates. This management neglect should also be reflected in the rate of return awarded to the Company. In the last rate case PacifiCorp requested an increase in the rate of return because of claimed superior management. The Commission correctly denied any such rate of return enhancement. In this case the Company's theory should be applied to lower the rate of return when it had admittedly poor management.

REVENUE ADJUSTMENTS

Glenrock Mine Closure

As with the prior case, Docket No. 97-035-01, the Company once again proposes to include in rates the closure costs associated with the Dave Johnston Mine (aka, Glenrock Mine). The Company's proposed adjustment would amortize the closing costs, which were estimated by the Company in 1997, over a three-year period. The Company's adjustment increases rate base by 2/3 of the Company's proposed write-off, and, at the same time, increases operating expenses by the 1/3 write-off.

In Docket No. 97-035-01, the Commission correctly determined that excluding the write-off from the 1997 test year would properly match costs and benefits. In particular, the Commission stated, "We conclude that the proposals of the Division and Committee did not result in any risk of cost-under recovery. Their proposal would change the timing of recovery, smooth coal costs over time, and afford the opportunity to better match cost-recovery with expected benefits."

The economic reason for closing the Glenrock Mine is the ability to purchase Powder River Basin coal at a lower cost. That did not happen until the latter part of *1999*. There was no change in the operations of the Dave Johnston Mine during the 1998 test year sufficient to warrant the start of the inclusion of closing costs in rates. Coal was still mined by the Glenrock Mining Company and delivered to the Dave Johnston Plant throughout 1998 and for the greater part of 1999. The closure of the mine occurred October 9, 1999, outside the confines of the 1998 test year.

The Company does not deny the facts that the mine actually closed in 1999 and that the vast majority of the coal utilized at the Dave Johnston plant in 1998 came from the Dave Johnston Mine. The Company, essentially, makes two arguments for the recovery of these post test-year costs within the test year:

1. The Company claims a significant fuel cost savings in 1998 as a result of the mine closure; and

2. The Company incurred reclamation costs in 1998.

Claim of Significant Fuel Savings Within the Test Year: PacifiCorp's claim of significant fuel savings within the test year resulting from the Dave Johnston Mine closure has been discredited by Committee witness Larkin's direct and rebuttal testimonies. In his rebuttal testimony to Division of Public Utilities ("Division") Witness Carl L. Mower, Mr. Larkin demonstrated on page 14 of the rebuttal and in CCS Exhibit 1R, how the claim of significant fuel savings is primarily attributed to the early retirement program. The savings calculated by the Company (based on the change in fuel costs from $8.44 per ton currently included in Utah rates and the proposed $8.02 per ton to be included in the rates to be established in this Docket) amount to a savings of $1,692,905. This is the only legitimate savings that the Company can claim ratepayers will benefit from. Mr. Larkin's rebuttal testimony, at page 14, demonstrates that 81% (or $1,381,028) of this reduction in fuel costs is attributable to the early-out retirement program and not the early closure of the mine. Almost all purported savings are a result of the early retirement program. Even if one were to attribute the difference of the fuel cost reductions of $311,887 to the closure of the mine, it pales in contrast to what the Division and Company would include in rates on a jurisdictional basis. The Division suggests that, on a jurisdictional basis, Utah ratepayers should pay $6.1 million, while PacifiCorp's adjustments would result in a rate increase of approximately $8.7 million. Offsetting these jurisdictional rate increases would be approximately 1/3 of the savings of $311,887, or approximately $100,000. Even if the Commission were to except this tenuous view that the proposed mine closure did produce some savings, they certainly are minimal when compared to the huge closure costs, which both the Division and the Company are asking ratepayers to pay.

Mr. Larkin further demonstrated, in CCS Rebuttal Exhibit 1.5R, that the Company's fuel savings will more than offset any mine reclamation costs that the Company might incur in the years 2000 through 2006. In fact, that exhibit, when corrected for mathematical error, shows that the Company will benefit by approximately $78 million. If the Commission were to grant the Company's and Division's amortization requests, it would be allowing the Company to recover the mine cost at least twice, once through the amortization procedure which both the Company and Division have recommended to the Commission, and a second time through the reduced fuel costs that are the economic basis for closing the mine in the first place. Larkin Rebuttal Exhibit CCS 1.5R demonstrates that the Company would, in effect, gain $78 million even under the scenario that Mr. Larkin is recommending to the Commission.

Both the Company and Division would have the Commission believe that there is some "financial uncertainty" created by not allowing the Company to begin to amortize the mine closure costs in the current rate case. The Company made this same claim in the last rate case, and the Commission's order on that point is just as cogent in this case as it was in that case:

> We conclude that the proposals of the Division and Committee did not result in any risk of cost-under recovery. Their proposal would change the timing of recovery, smooth coal costs over time, and afford the opportunity to better match cost-recovery with expected benefits.

That is exactly what needs to be done, and to do that the costs cannot be included in rates set based on a 1998 test year.

<u>Reclamation Costs</u>: The Company claimed, and the Division accepted the Company's argument, that final reclamation costs were incurred in 1998, and therefore, the amortization of the mine abandonment costs should begin in 1998. As Mr. Larkin pointed out in his rebuttal testimony, at page 16, the Company engaged in final reclamation at the Dave Johnston Mine in years prior to 1998. The Annual Report to the Wyoming Department of Environmental Quality ("WDEQ") shows that reclamation of 253.52 acres had occurred prior to 1983, and that an additional 823.36 acres had been reclaimed in post-1983. Therefore, the claim that final reclamation costs in 1998 heralded in some major change in reclamation activities is specious. The factual situation is that the Glenrock Mining Company has engaged in final reclamation of various properties which are

part of the Dave Johnston Mine over the last 23 years, since the inception of the Federal and State laws requiring mine reclamation in 1977. The fact that the Company spent $4.3 million of funds already collected from the ratepayers for such costs does not, in anyway, require the Commission to allow the rate recovery of any costs associated with the closure of the Dave Johnston Mine.

Prior Retroactive Mine Reclamation Costs Under-Accrual: A major portion of the costs the Company and Division recommend be recovered from ratepayers, starting with this rate case, are mine reclamation costs. Approximately $20 million for reclamation had already been recovered from ratepayers in 1998 and prior years via the inclusion of a charge in the cost of coal included in rates. The Company accrued an additional $33 million in 1997 for reclamation costs, which it claimed were a result of closing the mine early. Mr. Larkin, in his rebuttal testimony, at pages 17 and the top of page 22, and in Exhibit CCS 1.2R, shows that the $33 million requested by PacifiCorp for reclamation is the result of past under-accruals of costs. PacifiCorp knew it was under-accruing the costs. The Division has not seriously attempted to analyze the accrual of the mine reclamation costs to determine whether this is retroactive rate making. In fact, the Division compares it to the correction of an accrual without having done any detailed analysis or comparison of historical accrual rates used by the Company.

The Company's argument does not withstand scrutiny. Mr. Getzleman, who testified on behalf of the Company regarding the accrual of mine reclamation costs, states at page 15 of his rebuttal testimony: "As previously discussed, PacifiCorp determines an accrual rate for final mine reclamation expense based on Dave Johnston's expected life of mine production. The figures reported to the Wyoming DEQ ignore the concept of expected life of mine production."

Even after making these bold claims of how the accrual rate should be determined based on an expected life of mine production, neither Mr. Getzelman or the Company produced any such studies. However, Mr. Larkin did produce a Dave Johnston reclamation cost accrual study (which was provided to him by the Company), which was admitted as CCS Rebuttal Exhibit 1.6R. CCS Rebuttal Exhibit 1.6R specifically states that "The table reflects the cost of reclamation activities as required by the approved mine permit from the Wyoming DEQ and the Federal OSM." This exhibit directly refutes Mr. Getzelman's claim that the WDEQ requirements are ignored by the Company when it calculates an accrual rate.

Mr. Larkin, through CCS Exhibit 1.6R, also showed that the Company determined the accrual rate should be $.8435 per ton starting in 1985. The exhibit also states that "It is important to note that this table will be recalculated on an annual basis to reflect changes in total tonnage, the mine recovery plan and changes in mining and reclamation technology. The data will also be updated to reflect actual changes in mining and equipment costs over the previous year."

Even though the Company's internal memo on reclamation costs stated that the accrual rate would be updated each year, the Company has not produced one document showing that it complied with its own claim of how the accrual rate should be determined. The evidence presented through this and other exhibits demonstrated how the Company continuously reduced the accrual rate in the face of studies which indicated that it actually should have been increased.

Exhibit CCS 1.7R consists of a 1988 document entitled "Glenrock Coal Company Accrual Rate Study." The study deals specifically with the Dave Johnston coal field, and also refutes Mr. Getzelman's statement that accrual rate studies are not designed to comply with the WDEQ requirements. On the executive study at page 1 of the document, it states, in part, "This study was developed with the constraints of the existing permit commitments and Wyoming Department of Environmental Quality ("WDEQ") regulations in an effort to inform Pacific Power & Light Company of their existing reclamation liability, and the resulting impact on coal costs."

The study assumes five different scenarios for reclamation accruals associated with the south and central part of the Dave Johnston Mine. Based on the expected life of the southern part of the mine, an accrual rate of $1.30 per ton was recommended. The central mine portion had a recommended accrual rate of $.75 per ton based on its remaining life; however, PacifiCorp did not adopt either one of these reasonable approaches to determine a proper accrual rate. Rather, the Company chose the lowest accrual rate of $.61 per ton assuming a

40-year remaining life. Thus, the Company reduced the accrual rate adopted in 1984 of $.8435 per ton to $.61 per ton, even in light of the fact that its own studies indicated that the accrual rate should have been raised for the southern part of the mine.

Approximately sixteen months later, on November 29, 1989, in an internal correspondence (which was entered in the record as CCS Exhibit 1.8R), the Company again reduced the accrual rate from $.61 per ton to $.49 per ton based on a limited study related to the southern area. It appears that this $.49 per ton was used by the Company from November 29, 1989, to the closure of the mine, October 9, 1999. It is interesting to note that the internal memo states in the last paragraph "I feel this is a reasonable accrual rate which could be used for the south area if and only if a higher rate of $.66/ton is used for any tonnage removed from the central area in the future. To reduce the accrual rate to some amount below $.49/ton for the south area would create an unnecessary liability on future reclamation and mining activities." Even with this caveat, the Company reduced the accrual rate to $.49 per ton for the entire Dave Johnston Mine.

PacifiCorp witness Mr. Getzelman was incorrect in stating that the WDEQ's Guideline No. 12, Standardize Reclamation Performance Bond Format and Cost Calculation Methods, cannot be used when considering this issue because:

1. Costs are calculated as performed by an outside contractor;
2. Costs are calculated with the contractor utilizing its own equipment;
3. The Contractor would incur significant mobilization and demobilization costs;
4. PacifiCorp is instructed to use the details of Guideline 12 rather than expected cost to arrive at the backfill and grading costs; and
5. The Wyoming DEQ calculations include a 15.8% contingency fee.

First, the document itself states on page 2 of 38 that it is a guideline only, its contents are not to be interpreted by the applicant permittee or WDEQ staff as mandatory. So the Company could have made its calculation to conform with the actual costs if it thought it did not conform. Secondly, on page 4, it says that owning and operating costs were determined using the Dataquest cost reference guide except that the total and owning and operating costs have been adjusted in this package to reflect wholesale prices rather than retail. This refutes the Company's claim that the guidelines assume contractors are using their own equipment. It also refutes Mr. Getzelman's third contention that the contractor would incur significant mobilization and demobilization costs since the guidelines do not require that the Company make this assumption.

The Company's fourth contention that it is required to use the guidelines rather than expected cost to arrive at backfill and grading costs is refuted by the statement on page 2 of the guidelines, which states that this document is a guideline only. It is not to be interpreted by either the Applicant or Department as mandatory.

The fifth and final claim that the guidelines include a 15.8% contingency fee is refuted by the fact that when you compare the reclamation cost accrual, including the $33 million which the Company states is appropriate, to what it provided for its bond estimate on March 10, 1997, there is essentially no difference. The Company's accrual, at December 31, 1997, was $54,092,000. Its bond reclamation cost calculation to the WDEQ at March 10, 1997 was $54,574,600, a difference of $482,600. So the Company essentially is asking for the same amount from the ratepayer as it had been telling the WDEQ was the proper amount. To claim that there is a difference in the calculations which make one calculation unsuitable to use for the other is unsupportable.

Turning, finally, to the only document the Company has filed in support of its argument against the knowing, prior under-accrual claim, PacifiCorp Rebuttal Exhibit 8R, it is deficient on its face. First, the exhibit shows the Company not disturbing any more acreage after 1999. Mr. Larkin presented Rebuttal Exhibits CCS 1.11R and CCS 1.12R, which show the area of disturbed acres. He also explained why it is impossible to mine additional coal without disturbing acres farther north of the current mining area, and thus, incurring just as much reclamation costs as has been incurred in the past.

That exhibit also claims to be able to mine 4.2 million tons per year. During cross-examination, Mr. Getzelman was unable to identify any year in which the Company had mined 4.2 million ton of coal. He was also unable to state any year in which the Dave Johnston Plant burned 4.2 million tons mined by the Glenrock

Coal Company from the Dave Johnston Mine. If the Company could really refute Mr. Larkin's retroactive rate-making claim with a life of mine or economic study, it would have done so. The document entered by Witness Getzelman as Rebuttal Exhibit 8R does not do that.

The Commission cannot allow these costs into rates. They are the result of previous, knowing under-accruals by the Company. These costs should not be borne by customers today.

Systems Applications and Products (SAP) and Related Costs

In 1997 PacifiCorp decided to implement a Business System Integration Project ("BSIP") through a series of computer programs which are called Systems Applications and Products ("SAP"). There are several costs the Company wrote-off in 1997 and several costs it has incurred since that time which are interrelated with the Company's decision to move forward with the BSIP/SAP implementation. Those costs are as follows:

1. Computer software write-down;
2. Mainframe write-down;
3. Re-engineering costs; and
4. SAP programs.

The objective of the BSIP/SAP project was to design and implement a more efficient, integrated financial and information system which would capture data at one level and allow it to be utilized by other departments and systems throughout the Company. The following statement from Mr. Meier's Rebuttal Testimony provides the intent of the project:

> Communication and data flows throughout the Company are greatly improved, which in turn provides a better service to customers. Data that might previously be captured on a number of occasions at different locations and different systems, only needs to be captured once, and is then immediately made available to all departments across the Company.

Obviously, for the system to have a positive impact on productivity, it must be installed and fully functioning across the Company. This did not occur in the test year. Nevertheless, the Company still contends that approximately $10 million of revenue requirement associated with the write-offs and the SAP programs themselves ought to be placed in rates. The Company makes essentially two arguments to justify the inclusion of the SAP programs and the associated write-offs in rates. The two arguments are:

1. The SAP programs were implemented as a pilot project at the Naughton Station and therefore were used and useful, and
2. The SAP programs effectuated cost savings implemented through the early retirement programs.

Naughton Plant: The Company's report to the Board of Directors characterizes the implementation of the SAP program at the Naughton Plant as a "pilot" program, and the Company has not disputed that. A pilot program is a trial run, an implementation used only to determine if it is feasible or workable to implement the procedural program being tested. A pilot program cannot accomplish or achieve what the Company states the SAP programs were designed to accomplish. That is, that information would be entered once at the Naughton Plant and subsequently could be utilized in every system throughout the Company. In other words, the financial information would flow directly to the Company's financial statements in total as would each and every operating plant within the Company's system. This could not occur for the Naughton Plant because SAP was not implemented in any other operating plant in the system until 1999. The information could not flow directly through to the financial statements because the financial statements were produced by the Legacy computer system throughout 1998.

Even Mr. Meier's summary on the witness stand [TR 367:8-11], indicates that the rollout at the Naughton Plant could not have provided any productivity gains. He states "SAP's real strength is in its ability to provide on-line real time integration of information between various functions of the operations from a single data base."

Obviously, with only the Naughton Plant utilizing SAP in 1998, a single database could not be developed, and no integration of on-line information could be utilized. Information that would be integrated into the functional areas of work management, material management, finance and human resources could not be inter-linked because the majority of the Company was not using SAP during 1998. Mr. Meier's cross, [TR 382] also verifies that the majority of the Company's operations utilized the old programs throughout 1998. Mr. Meier was asked:

Q: And the software, it sounded like that it was implemented in ’98 but not all of it?
A: This is right. It was implemented at Naughton, at the Naughton Plant, in September of 1998. At that point, the employees of the Naughton plant began using the SAP system for all their day-to-day activities. So they stopped using the old system, with the exception of one function. They did need to use the old system to get historical data. The rest of the Company continued to use the old systems until they were converted in 1999.

The lack of integration of the entire system essentially renders it useless, or of very little value, to the Company or the ratepayers in 1998.

Regarding the computer write-down costs related to the implementation of SAP, the prior systems were either utilized throughout 1998 or are directly related to the implementation of the SAP programs. Starting with the write-off of the software programs, the Company has acknowledged, as previously quoted from Mr. Meier’s cross examination, that the Legacy programs were utilized throughout 1998. Departments such as work management, materials management, finance and human resources all used the Legacy programs throughout 1998. The SAP programs did not replace this software in 1998 and any productivity gains resulted from the utilization of the old programs.

The Company has separately requested an amortization of re-engineering costs. It is undisputed that the re-engineering costs are an integral part of the BSIP/SAP implementation. They cannot be separated either for the purpose of rate making or for the implementation of the SAP programs. Mr. Meier acknowledges at page 379 of the transcript, when he was asked a question related to the benefits of re-engineering, as follows:

Q: My question, though, related to, are the benefits from the re-engineering program expected to occur over that five-year period?
A.Yes, they are. In fact, the benefits of the re-engineering program and the benefits of the SAP implementation are sort of intertwined. You can’t pull the two of them apart. Because the SAP technology was really an enabler of being able to get the benefits of the reengineering of the business processes.

The re-engineering costs cannot provide benefits separate from SAP. They are, as Mr. Meier admits, intertwined. The Commission must therefore reject any amortization of the re-engineering, because the associated benefits flow from SAP, and SAP was not used and useful in 1998.

The last remaining cost associated with the SAP programs was the write-off of the mainframe computer. The Commission must also reject this cost as being related to 1998, because it is, again, directly related to the implementation of the SAP programs. Even though the Company attempted to distance themselves from its statement to the stockholders, the Company acknowledged in its Annual Reports to stockholders that the write-off of the mainframe computer was directly related to the implementation of SAP programs. Cross Examination Exhibit 32, which is a page from the Company's Securities and Exchange Commission required 1998 Annual Report, states clearly that the mainframe computer and the software were written-off as a direct result of the adoption of SAP. Given that fact, and the fact that SAP was not used and useful in 1998, all costs associated with SAP must be removed from this rate case in order to set just and reasonable rates.

Claimed Productivity Benefits: Turning now to the Company's second argument that SAP produced productivity benefits in 1998, which are purportedly reflected in the early retirement program and other alleged cost savings, the Commission should be skeptical. First, the Company was asked to produce such documentation regarding associated cost savings early on in this case. No such study or documentation was produced when it was requested. However, in Mr. Meier's *rebuttal* testimony, the Company then claimed that SAP fostered workforce reductions, but it again produced nothing other than Mr. Meier's unsubstantiated claim. No documentation was produced, no calculations, no evidence of any probative value. Company Witness Meier acknowledged that one could not determine the level of any savings related to SAP from the early retirement program. [TR 411:1-11, 413:4-24]

PacifiCorp's former CEO and President, Fred Buckman, acknowledged that the Company had lost control of its costs. (See Exhibit No. CCS 1.2, pages 1 through 6.) It stretches the imagination to believe that a Company that has an acknowledged poor track record in controlling its costs could somehow produce productivity benefits almost a year prior to the rollout of a program which it claims produced such benefits. Such claims should be rejected by the Commission; first, because they are not supported, and secondly, because they were made at the end of the case without granting parties the ability to analyze and refute these unsupported claims.

Additionally, Exhibit No. CCS 1.1R and Cross Examination Exhibit No. 30, which are the same document, show the Company's business case model for the implementation of SAP. This model shows that no cost savings are realized in the first year of implementation, and it is not until year two that approximately $25 million of potential savings are realized. The Company's own analysis shows that the SAP implementation will not produce any savings until at least a year following implementation. Thus the Company's own internal documentation refutes its claim of cost savings in 1998.

Systems Application Product (SAP) Removal: The final piece in the SAP related cost adjustments is the removal of the SAP costs themselves from the test-year operating expense and rate base. In connection with this, the costs associated with the Legacy systems, which were actually used in 1998, should be restored to the test year. The reasoning is as set forth above – the SAP system did not become functional and on-line until 1999. The productivity gains to be achieved from the SAP system result from integration of numerous functions. Such gains could not have occurred in 1998 – the system was not functional except as a pilot program at one generation plant. Yet the Company would include over $5.8 million dollars in test-year expenses. That would create a mis-match between costs and benefits.

In addition, the SAP costs themselves need more careful review. The system was originally conceived to support a number of unregulated entities some of which are no longer part of the PacifiCorp business. The SAP costs are also already $20 million over budget. The costs need to be carefully examined to determine their used and usefulness and the proper allocation of the total costs between regulated and non-regulated entities. The costs should not be amortized in rates until benefits actually begin to flow to ratepayers that are at least equal to test-year costs.

Customer Service System (CSS) Expense Disallowance

Both the Committee and Division recommend adjustments to disallow one-third of CSS maintenance expense, consistent with the stipulation in the last rate case. The Division adjustment removes one-third of the CSS maintenance contract. The Committee agrees with this adjustment. The Committee also believes that for the same reasons one-third of all CSS maintenance expenses should be removed from test year expenses. That is consistent with the stipulation. Other facts support the adjustment as well. The CSS system did not function properly in 1998. Incorrect billings were sent, and as a result collection activities were suspended. This caused bad debt expense to increase. The additional maintenance costs that are included in the Committee adjustment were incurred in attempting to correct problems with the CSS system. Those costs should not be borne by ratepayers.

Condit Dam Removal

This adjustment was also one of the issues in the last rate case – and the decision there still holds. There was no agreement to remove the dam in 1998. An agreement was signed in September 1999, but that is not final. There are numerous contingencies in that agreement, and it has not been approved by the appropriate federal regulators. The proposed agreement calls for dam removal to begin in 2006, or earlier if funds can be obtained from sources other than PacifiCorp. It is very possible under this agreement that PacifiCorp will not pay all, or any, of the removal costs.

The Company's request is to allow it to collect from ratepayers "supplemental" depreciation. Such a request violates the stipulation in the recently concluded PacifiCorp depreciation case. In that case the depreciation rates for Condit were increased beginning April 1, 2000. The Commission may recall that one of the reasons the depreciation case was able to be settled by stipulation was that the effect of the changes, when offset by the accounting adjustment contained in that stipulation, resulted in a slight decrease in depreciation expense to ratepayers until the agreed upon next depreciation case. An attempt by PacifiCorp to get an additional $2 million in depreciation in this case violates the stipulation and the reasons it was entered into. In addition, *Utah Code Annotated* § 54-4-24 states that a public utility "shall conform its depreciation accounts to the rates so ascertained, determined and fixed" by the Commission. That is why utilities have depreciation cases – so the Commission can set going-forward depreciation rates. There is no authority for the Commission to retroactively revise one depreciation rate, particularly without even an application to do so. The proposed adjustment is necessary to remove an accrual that should not be included in rates based on a 1998 test year.

Y2K Expenses

The Company requests full inclusion of over $10.2 million in Y2K expenses in the test year. That would be inappropriate. It would be difficult to find a better example of a non-recurring expense. As such, they could rightfully be fully excluded from rates. The Committee, however, has not recommended that. The Committee recommends amortization of these expenses over five years. This amortization is in line with the amortization of extraordinary revenues from the SO2 emission credit sales approved by the Commission in the 1997 test-year rate case.

The Division has proposed a similar adjustment, using a five-year amortization. The only difference is in the calculation of the amount to be included in rate base. The Division adjustment (DPU 4.7) added about $8.2 million to rate base, using the balance after one full year of amortization. The Committee adjustment (CCS 1.10) adds about $9.2 million to rate base using an average rather than year-end number. If the Commission decides that average rate base is the appropriate approach, the Committee's adjustment should be adopted. If year-end rate base is appropriate, the Division's adjustment should be adopted. In either event, the Y2K costs should be amortized over a five-year period.

WAPA Wheeling

In the 1960's the Company or its predecessor entered into a long-term wheeling contract with the Western Area Power Administration ("WAPA") at a very low rate with no escalators. The rates are now significantly below comparable, FERC wheeling rates. Both the Committee and Division have proposed adjustments to impute revenue at the level of current FERC wheeling rates. The Company's opposition to this adjustment is troubling. The Company asserts that significant benefits have accrued to customers as a result of this bargain-basement wheeling contract. Yet, it has failed to provide a cost-benefit analysis to substantiate this claim. More importantly, in 1983 this Commission issued a Report and Order [Cross 52] which reaffirmed its policy of imputing revenues for this wheeling contract. That Order states:

> Utah Power was aware of this Commission's regulatory treatment of the wheeling agreement and cannot expect different treatment simply because it has assumed the contractual wheeling obligation. The Commission believes the Division's proposed adjustment will accomplish, as in

> previous CPN cases, a proper allocation of transmission investment and expenses between retail customers and non-jurisdictional preference customers. The Commission therefore finds that the Division adjustment is appropriate.

Id. at 7.

This is interesting in two ways. First, though less important, it shows that at the very time customers were supposedly getting all of these benefits PacifiCorp claims, the Commission was imputing revenues to prevent a subsidy of this below-cost contract. Second, and most important, it shows that this Commission has already ruled on this very contract. PacifiCorp has not only ignored this Order, but makes no apology for it. The Company's position seems to be that it is not obligated to comply with past Commission orders.

This seems to be the same attitude that gave rise to the Utah Supreme Court decision in *Salt Lake Citizens Congress v. Mountain States Telephone & Telegraph Co.*, 846 P.2d 1245 (Utah 1992). In that case it was Mountain Bell that failed to reflect a Commission ordered adjustment in it filings and rate cases. The *Salt Lake Citizens Congress* opinion makes clear that Commission orders have the effect of law and are thereafter binding on the Company, and others including non-parties. The 1983 Order of this Commission was and is binding on PacifiCorp in this and all other rate cases since then. In its strongly-worded opinion the Supreme Court chastised Mountain Bell for violating the Commission's order, and also chastised the Commission for allowing it to happen without recourse. In this case, at a minimum, an adjustment imputing revenue needs to be made. In light of the strong words of *Salt Lake Citizens Congress* further remedies may be appropriate.

Sacramento Municipal Utility District (SMUD)

In 1987 PacifiCorp received $94 million from SMUD in connection with BPA power rights, and entered into a long-term firm wholesale contract with SMUD at the extremely low price of about $16/MWH. The contract was priced significantly below market when it was entered into, and remains so today. The $94 million PacifiCorp received has never been credited to ratepayers or used in any way to offset this below-market firm contract. Even PacifiCorp agrees that an adjustment is needed to impute additional revenues to this contract. The question is how much. The Division has historically made an adjustment using the price in a Southern California

Edison ("SCE") firm contract entered into by PacifiCorp in the same time frame as the SMUD contract. That adjustment amounted to about $2.1 million at the beginning of the 1997 rate case. Oregon likewise has included a SMUD adjustment in its 1997 and 1998 filings based on the SCE contract – leading to adjustments of $3.2 million in 1997 and $2.5 million in 1998.

In this case, however, the Division would impute revenue for this *firm* contract based on non-firm prices used by Idaho regulators. The Committee believes that it makes little sense to use non-firm prices for a firm contract. Even Mr. Burrup admits that the Division's imputation price is inappropriately low and needs to be adjusted upward.

The Division apparently acceded to the Company's objections to using the contemporaneous SCE contract. That also does not make sense. The best indicator of what the SMUD contract price should have been is the contemporaneous SCE contract. The fact that the SCE contract was later amended has the same relevance as the fact that sales contracts in 1980 or 1990 were at a different price. The relevant question is what was the fair market price in 1987 and the SCE firm contract provides that.

Mr. Yankel has approached this imputation in a different way and arrived at an adjustment of a similar magnitude: $2 million. [CCS 8.4R]. The basis for Mr. Yankel's imputed price is contained in his confidential rebuttal testimony.

The Division admits that its adjustment is inappropriately low. Use of either the SCE imputed price, as the Division previously did and as Oregon currently does, or Mr. Yankel's adjustment, provides a more proper imputation of revenues for this under-market priced contract.

Pension Regulatory Asset

With this issue we again have PacifiCorp making a claim directly contradictory to its own statements and financial reports. In *1997* PacifiCorp wrote-off a regulatory asset for pensions. In its 1997 Annual Report to Shareholders PacifiCorp stated:

> Also in 1997, the Company evaluated all its regulatory assets and liabilities applicable to deferred pension costs which relate primarily to a deferred compensation plan and early retirement incentive programs in 1987 and 1990 and determined that recovery of these costs was not probable. As a result, the

Company recorded an $87 million write off of its deferred regulatory pension asset, since the Company does not intend to seek recovery of these costs. However, the company will seek recovery for its current and future pension costs.

[PacifiCorp 1997 Annual Report to Shareholders, p. 49, entered as Cross Exhibit 7].

There was a 1997 test-year rate case in Utah. PacifiCorp did not seek recovery of any portion of this write-off. Now, in a 1998 test-year rate case PacifiCorp seeks recovery of costs that:

1. Are not on its books in 1998 and for which it did not seek recovery in the year it wrote it off;

2. Costs it told the world, including its shareholders and regulators, that it would not seek recovery of; and

3. Stem from 1987 and 1990 early-out programs and a deferred compensation plan from the 1980's.

This is nothing more than an attempt to resurrect costs that were properly written-off and take a shot at getting something for nothing. There is nothing on the Company’s books for which to recover this expense. Any “recovery” would be a windfall. It is not timely in other ways as well – the expenses are for costs in the 1980's and in 1990.

The Company would have the Commission believe that recovery of this asset is tied to its request to switch from pay-as-you-go to accrual for current pension expense. That is misleading. The Commission could grant the application, made in passing in this 1998 test-year case, to change to accrual accounting, while denying recovery of the asset PacifiCorp wrote off for good in 1997. If they were tied together, the request should have been made in the 1997 test-year rate case. PacifiCorp has presented no valid reason that it should be allowed to resurrect what it wrote-off its books in 1997.

Property Insurance Reserve

PacifiCorp improperly allowed its property insurance reserve to be depleted since at least 1992. The Company seeks to include a significant one time catch-up accrual to bring its reserve from $157,000 to $8 million. The reserve has been declining for at least five years. At no time since 1992, and possibly before, has the reserve ever been as high as $6 million. The Company claims that it would be imprudent to not bring the reserve to the $8 million level. If that is the case then the Company has been imprudent since at least 1992, and putting this large catch-up accrual into rates would be improper.

The reserve does need to be re-established. Property insurance expense for the five years preceding the test year averaged $9.1 million. The Committee recommends allowing that amount into rates, plus $1.2 million to begin re-establishing the reserve. This is a reasonable approach to re-establishing a fund that has been depleted over many years, while not foisting all of the cost on ratepayers in one test year. Committee adjustment 2.6 should be adopted.

Workers Compensation Expense

The Workers Compensation expense is similar to the just-discussed property expense adjustment. In the test year PacifiCorp expensed an additional $1 million (total company) for Workers Compensation to recognize and compensate for under-accrual in prior years. This is again a one time catch-up of prior under-accruals. It is a lump-sum catch up, not an attempt to build up the reserve over some period of time. It would be improper to include this catch-up in setting going-forward rates. The expenses are specifically for prior years, and should be removed from the test year.

Noell Kempff Climate Action Project

This project involves preventing the logging and clearing of about 3.6 million acres of land in Bolivia. The Company maintains that this project may, at some unknown time in the future, provide carbon dioxide credits that may have some value. While the Committee certainly has nothing against environmental preservation projects, ratepayers should not be forced to pay for this project at this time. There is currently no law requiring such carbon dioxide offset, and no law creating any credits. PacifiCorp admits that it is uncertain whether any benefits of this kind will arise from the project. This is a 30-year project and PacifiCorp seeks to include 44% of the total project cost in the 1998 test-year. That, on its face, is not proper. In addition, there was no matching of benefits to these costs in the 1998 test year. The Committee therefore recommends that these costs be excluded from this test year.

Solar II Amortization

PacifiCorp seeks to include $434,884 (total Company) in test-year expenses for costs associated with the Solar II Research and Development Project. The Committee proposes, in Committee adjustment 3.7, that these costs be excluded. During the course of the hearings, the Division stated its agreement with this adjustment. The costs are for research costs incurred by the Company from 1992 to 1995. The Company never requested or received authorization to defer these costs for future recovery.

In the last rate case, 97-035-01, the Company made the following statement in response to a data request regarding the Solar II project:

> Since this is an experimental R&D project, the deferred costs and amortization expense should not have been included in electric utility operations. The company will make an adjustment to move the amortization expense below the line to an unregulated account. The unamortized balance of the project was not included in rate base in the test year.

[Cross Exhibit 69.] The Company was right in that case, but has now attempted to completely change its position. Such reversals should not be condoned by the Commission. These are experimental R&D costs , and are also out-of-period. The costs need to be removed from test-year expenses.

Uncollectible Expense

Uncollectible expense was extraordinarily high during the 1998 test year. Even PacifiCorp recognizes that an adjustment must be made to uncollectible expense. It proposes to use a three-year average using 1996 - 98. The Committee recommends a three-year average using 1994 - 96. The Division recommends a four-year average using 1993-96.

In the last rate case this Commission determined that 1997 uncollectible expense was inordinately high and made an adjustment to that expense. In an attempt to determine an appropriate level of uncollectible expense it would be improper to use 1997 – using a year that has already been found to not be reasonable would generate unreasonable results. The Committee's and Division's positions are consistent with this.

In the last rate case the Commission used a three-year average to determine the appropriate level of uncollectible expense. That is what the Committee is proposing in this case. The Division would include an additional year, 1993, in its average. No cogent justification for using four years instead of the three years used in the last case has been put forward and the Committee recommends that the Commission determine the proper level of expense using a three- year average as was done in the last case.

Relocation Expense

Numerous, non-recurring relocation programs took place during 1996 and 1997 as a result of consolidation of the local field offices into two business centers. In 1998, significant relocations occurred as a result of the accounting department relocation. The Company has adjusted for the accounting department relocation effectively amortizing the expense over five years. However, even after that adjustment, about $3.3 million would remain in test-year expenses and test-year expenses are not reflective of normal cost levels. Adjustment CCS 3.3 more properly reflects a normal level of expense. That adjustment sets test-year costs at a five-year average level, plus 1/5 of the difference. The benefits of the relocation do not appear in the test-year. The additional costs should be amortized over five years as the Company has done with the accounting department expenses. The adjustment is reasonable and necessary to have test-year expense reflect a normal level of relocation expense.

Bridger Coal Company (CCS 3.1)

PacifiCorp seeks to include in its rate base a portion of the rate base of Bridger Coal Company. Included in that amount is Bridger's accounts receivable balance. The receivables relate to amounts for an early retirement and coal sales. PacifiCorp has agreed that the portion of the accounts receivable balance related to the early retirement program should be removed. This Committee adjustment removes the rest of the accounts receivable balance. *All* of the receivables are due *from PacifiCorp*. PacifiCorp is seeking rate base treatment of amounts it owes to another Company. The receivables should be excluded from rate base in this case.

In the Company's rebuttal testimony PacifiCorp witness Jeff Larson indicated that Dan Peterson would present rebuttal testimony on this issue. No rebuttal testimony was filed by Mr. Peterson or any other witness.

PacifiCorp has attempted to submit rebuttal testimony in the joint narrative exhibit. There is no testimony on record to support the assertions in the joint narrative. There was also no opportunity for the parties to examine PacifiCorp witnesses on its position because that position was not raised in the hearings. The text on this issue from the Company should be stricken. The adjustment is proper, and no opposition to it appears on the record.

Incentive Compensation

PacifiCorp asserts that incentive compensation is an important component of the "total compensation package" required to attract and retain qualified employees. The salient issue is whether Utah ratepayers should incur all, part or none of the expense attendant to incentive compensation. In its Order in Docket No. 97-035-01, the Commission furnished some guidance on this issue that merits repeating. On page 12 of the above Order, the Commission explicitly stated "If the expenses of an incentive plan are to be recovered in rates, the plan's primary goal must be enhancement of customer service." Operational efficiency is also noted in that Order as a key measure of performance.

In this 1998 test-year case, PacifiCorp failed to show that performance targets were met in the key areas of customer service and operational efficiency such that ratepayers should fund incentive compensation. And it would be difficult for the Company to make such a showing since they were acquired by ScottishPower, in part, because of the lack of employee focus on customer service and cost containment. The Utah Commission's Order in the ScottishPower Merger Case (Docket No. 98-2035-04) is instructive on this point: "The record shows that the non-production operation and maintenance expenses PacifiCorp incurs to provide service have grown in recent years beyond that expected by an efficient utility operation. According to PacifiCorp witnesses, management was "distracted" by a failed global growth strategy and did not control utility costs carefully." [Order, page 12.]

Utah ratepayers should not be saddled with the full amount of incentive compensation expense proposed by PacifiCorp in this 1998 test-year rate case. PacifiCorp management freely admitted in the merger proceeding that it was not focused on its core regulated utility business during the 1998 test-year. The Committee recommends that the Commission enter a finding which disallows 62.5% of the incentive compensation expense.

Supplemental Executive Retirement Plan (SERP)

The SERP represents an extra retirement plan that is available to a select group of 34 PacifiCorp executives. The Company furnished no evidence showing that Utah ratepayers benefitted from the SERP in the 1998 test-year. In fact, the Utah Commission, in its Order in the ScottishPower Merger Docket, opined: "PacifiCorp testifies, and we conclude, that no detailed and well-formulated business plan exists for PacifiCorp's utility operations in the unmerged case...we conclude that the transition to a new management team poses less risk for customers than would retention of existing management." [Utah Commission Order, page 13]

The SERP benefits only the highest ranking PacifiCorp executives – the very executives that were not focused on cost containment measures associated with domestic electric operations until late in the 1998 test-year. In the ScottishPower Docket, the Utah Commission itself concluded that PacifiCorp management lacked a definitive business plan for PacifiCorp's utility operations. Poor executive performance should not be rewarded by making ratepayers fund the Company's SERP program. The Committee strongly recommends that the Commission disallow all of the SERP-related expenses in the 1998 test-year.

Wholesale Firm Contracts

The Committee, through Mr. Yankel, has provided compelling testimony regarding the need to make a revenue imputation for specific long-term firm wholesale sales contracts. An adjustment is necessary to reduce the subsidy paid by Utah retail ratepayers.

The genesis of the need for this adjustment is as follows. The Company has for some years used the "revenue credit method" of dealing with costs and revenues from wholesale transactions. The underlying premise is that wholesale sales are made to benefit, i.e. lower the costs to, firm retail customers. That was the theory and explanation of PacifiCorp in 1993 when it created the document *PacifiCorp and the Wholesale Market – An Overview*. [Cross Exhibit 43] In the five years since that time, two things have happened. The volume of firm wholesale sales has increased dramatically so that they are presently about half of all system sales. And at the same time the prices for these firm wholesale contracts decreased significantly. The prices have fallen to such a level that in 1998 the average revenue from firm wholesale sales fell short of the average embedded cost of production and transmission resources. Retail ratepayers subsidized firm wholesale sales.

These are fundamental changes from the situation when the revenue credit approach was adopted. The Committee recommends that a forum be established to consider alternatives to the revenue credit approach. In the mean time, a revenue imputation needs to be made to lessen the subsidy from retail ratepayers. As a temporary measure, the Committee recommends imputing additional revenues to intermediate- and long-term firm contracts that are priced below the average embedded cost of production and transmission resources.

Mr. Yankel has recommended two possible "floor" prices to be used in such an imputation. The first is the average of interruptible special contract prices in Utah. These by their nature are of lower quality than the wholesale firm contracts. Applying this floor price creates an adjustment of about $8.2 million. The other floor price considered is the average price of four firm special contracts in Utah. These contracts are of the same quality as the wholesale sales – they are contracts for firm power. Using this price as a floor creates an adjustment of about $20.2 million. The Committee believes that either of these adjustments is conservative – neither would elevate the wholesale contract revenues to the average embedded cost of production and transmission resources. The proposed adjustment is also only a temporary measure until an alternative to the revenue credit approach can be fully considered.

<u>Time of Firm Peak Loads</u>

Over the past few years, PacifiCorp has been increasing the volume of firm wholesale sales. During the 1998 test year, about 50% of PacifiCorp's total firm sales involved firm wholesale transactions. Since firm wholesale sales represent approximately 50% of total firm sales, the Committee believes that the time of peak demand on the PacifiCorp system should appropriately reflect the combined monthly loads of firm retail and firm wholesale customers. Committee witness Yankel recommends an adjustment of $4,261,005 (Utah basis) stemming from a change in Utah's System Capacity (SC) and System Generation (SG) allocation factors.

PacifiCorp challenges the Committee's proposed adjustment primarily on three levels. First, the Company argues that a change in the measurement of the hour of system peak is an allocation issue and should first be discussed by all states at a PITA meeting. However, the Company initiated this instant proceeding where 50% of total test year sales involved firm wholesale sales. The Committee finds it troubling that PacifiCorp would attempt to require a party to take an issue to PITA for resolution, prior to raising it for consideration in a rate case before the Commission that has the authority to actually decide the issue. That would hamstring the efforts of parties like the Committee, UIEC, and the LEG to effectively represent Utah residential, commercial and industrial customers in rate case proceedings. A party like the Committee certainly has the legal right to propose allocation-related adjustments in a rate case. PacifiCorp's argument should be dismissed without hesitation.

Second, the Company argues that it does not have the same long-term obligation to serve wholesale firm contracts vis-a-vis firm retail loads. However, PacifiCorp includes long-term firm wholesale transactions in its system resource planning (RAMPP) requirements. In the 1998 test year PacifiCorp dispatched resources (i.e. operated its system) to meet both firm retail and firm wholesale peak load requirements. The Commission, therefore, should give little weight to this Company argument.

Third, the Company argues that when deferred tax income tax factors are updated as a result of changing the SC and SG allocation factors, the size of the proposed adjustment is greatly diminished. The Committee acknowledges that a deferred tax "offset" needs to be made to its proposed adjustment, but we cannot verify that the deferred tax information provided by the PacifiCorp is accurate and reliable. Specifically, the Company's updated deferred tax allocation factors for all PacifiCorp jurisdictions produces counter-intuitive results. For instance, the SC, SE and SG allocation factors for both Wyoming jurisdictions increased, but the allocation factor for deferred income tax expense decreased and so did revenue requirement.

Clearly, the large volume of firm wholesale sales in the 1998 test year impacted the time of monthly system peak demand – an impact that should be recognized in setting test year rates. The Committee's recommended adjustment is reasonable and should be adopted by the Commission.

Allocation of Special Contract Revenue

The system-wide allocation of the loads and the revenues of firm Special Contracts that were either amended or newly-signed after January 1, 1997, greatly disadvantages Utah retail ratepayers. Utah is negatively impacted because a disproportionate amount of post-1997 firm special contracts (new and amended) were consummated in other states. Since the revenue shortfall is spread across all states, other Commissions have apparently been "permissive" in approving firm special contracts. It is one thing to have Utah retail ratepayers subsidize firm special contracts in Utah; it is a very different matter to have Utah retail ratepayers subsidize firm special contracts in states outside this Commission's jurisdictional authority.

The Committee's recommendation to apply "situs" rate making treatment to firm special contract loads and revenues amounts to a prudent course of action. It places control over the decision to approve or not approve a proposed firm special contract appropriately in the hands of each state commission. By adopting the Committee's proposed adjustment (a revenue requirement decrease of $4,789,997), the Utah Commission will ensure that Utah retail ratepayers do not bear the impact of revenue shortfalls attributable to below-tariff special contracts approved in other states.

Power Costs

Committee witnesses Falkenberg and Cardwell addressed power cost issues. (These issues are set out in detail in the joint narrative.) Various adjustments were proposed and PacifiCorp and the Committee have resolved a significant portion of the disputed issues. In resolving those issues the Company agreed to revenue decreases of about $4.6 million on a Utah basis. Three issues remain outstanding:

<u>(1) Actual secondary sales and purchases.</u> Mr. Falkenberg recommends an adjustment to use actual market prices for secondary sales and purchases in the PD/Mac model. This adjustment is necessary because PacifiCorp relies on inputs from an unproven and unreliable Monitor Model to develop "normalized" market prices for

secondary sales and purchases. The Monitor Model was purchased by PacifiCorp in conjunction with stranded cost analyses. Division witness Wilson testified that she has found the model to be a very poor predictor. [TR 1204:18 - 1205:18] The Company offered no evidence demonstrating that the "normalized" prices generated by the Monitor Model are reasonable for rate making. Mr. Falkenberg testified that the logic of the Monitor Model is inconsistent with the logic of the PD/Mac model itself.

Numerous inputs are used in the PD/Mac model as starting points to normalize net power costs. The Committee recommends that in this 1998 test-year that actual market prices for secondary sales and purchases be used, rather than "normalized" prices from an unreliable forecasting model. We have actual 1998 data. It makes little sense to use questionable model-developed data in its place. One of the main advantages in using a historical test-year is the ability to use actual, historical data rather than argue about the accuracy of competing forecasts. This adjustment is consistent with that approach.

(2) Actual short-term firm sales and purchases. The rational for this adjustment is the same as that just discussed – Committee witness Falkenberg proposes using actual market prices for short-term firm sales and purchases in the PD/Mac model. Again, actual data is available and should be used.

The "normalized" prices produced by the Monitor Model forecasting are applied in blanket fashion to short-term firm and also to secondary sales and purchases. Since secondary sales and purchases exemplify non-firm transactions, it would make sense that short-term firm sale and purchase prices would be higher. The price difference between non-firm and firm transactions are not recognized in the Monitor Model.

This adjustment also eliminates losses from short-term firm transactions that occurred in 1998. If those losses are not removed Utah ratepayers will bear the financial burden of mistakes attributable to PacifiCorp's wholesale trading activities. Those losses should not be borne by ratepayers.

(3) Wyodak fuel adjustment. This adjustment would bring the Wyodak fuel contract price in line with market price. PacifiCorp recognizes that this contract is above-market and should be eliminated. PacifiCorp witnesses testified that they have even attempted to buy-out the contract – though no specifics of the attempts were given.

The Commission cannot determine from that testimony if PacifiCorp has made reasonable efforts. In their 1991 Coal Audit Report, EVA recommended that PacifiCorp pursue a buyout of that contract. In nine years, nothing visible has happened. That is not surprising. If ratepayers continue to fund this above-market contract, why should PacifiCorp expend time and energy buying out the contract and reducing coal costs? The reality is nothing is likely to happen unless PacifiCorp has some financial exposure. An adjustment bringing the contract price in line with market price will do two things: it will provide the proper incentive (which is currently lacking) to PacifiCorp to expeditiously address this above-market contract; and it will also prevent ratepayers from bearing the financial burden of this contract that EVA recommended that PacifiCorp get out of nine years ago. The adjustment is necessary and proper.

1998 Early Retirement

With respect to the 1998 early retirement program, PacifiCorp proposes to amortize the costs over five years and also include estimated net savings from the program. That net savings is the total projected savings reduced by the backfilling of some vacated positions. In its rebuttal testimony PacifiCorp changed its numbers on this issue. It agreed that its backfilled adjustment needed to be reduced by 82 positions, and that a 46.25% hiring lag factor was more appropriate than its originally filed 37.5% factor. There remain three differences between the Company position and the Committee's. Those differences are well laid out in the joint narrative exhibit. They all center around the Company again changing its position and numbers during this case, and making claims in direct contradiction to its Annual Report to Shareholders. The conclusion to be drawn from this is that PacifiCorp's claims are not credible. As set forth in the joint narrative, the Committee's adjustment is proper and necessary to properly reflect the savings associated with the early retirement program.

1998 Pension Expense

PacifiCorp has overstated its pension expense and understated its rate base treatment of costs associated with the 1998 Early Out Programs. The overstatement of expense arises from the Company's inclusion of costs on an accrual basis, rather than the Commission approved and ordered pay-as-you-go basis. The Company's direct testimony does not even address this change or specifically request approval of this change. No other filing has been made requesting such approval either. PacifiCorp should not be allowed to make such a change in this way.

In its rebuttal testimony the Company claims that changing to an accrual basis will decrease expense. But, the Company's October 12, 1999, newsletter to its employees states:

> Company contributions and a strong stock market have dramatically improved the standing of the retirement plan – two years ahead of schedule.
>
> Management's 1993 decision to make significant annual contributions – an average of more than $62 million per year – combined with one of the strongest stock markets in history has led to the retirement plan's assets now comfortably exceeding its retirement liabilities, as calculated by an independent accounting firm.

[Cross Exhibit 9]. What this means is that under an accrual method an expense will exist, but funding may not be necessary. That would make pay-as-you-go less expensive. Once again, the Company's own documents are directly contradictory to its position in this case. The Committee adjustment is appropriate and should be adopted.

Line Extensions

The parties have essentially agreed that a change in the policy for line extensions is appropriate. The dispute arises regarding how this change should be reflected in the current rate case. It should be remembered that PacifiCorp originally proposed this change a few years ago outside of a rate case. It withdrew that proposal because it recognized that there is a revenue impact of this change, and so the change needed to be made in a rate case. Now, however, it claims that there is no revenue impact that needs to be addressed in this rate case.

The Company's contends that this is an out-of-period adjustment and should not be reflected within the test year. Additionally, the Company claims the implementation of the line extension policy capping the Company's investment in line extensions at $700 for residential customers and as a percentage of projected revenue for other customers will not reduce the Company's investment in line extensions; rather, the average will essentially remain the same.

As Mr. Larkin explained in his testimony, the 1998 test year is a surrogate or model that the Commission uses for future relationships between revenue, expenses and investment. If we change one of these components, a change must be reflected within the test year. This is because the relationship we are attempting to establish between these components will change. The adoption of a line extension policy will reduce the amount of investment that the Company will have to make in line extensions. This is both mathematically and intuitively correct. If the Company is currently incurring $1,200 of investment per line extension and that is capped in future periods at $700, the investment in each additional line extension has to decrease by $500. Mr. Larkin proves this mathematical fact in Rebuttal Exhibit CCS 1.10R. This refutes Mr. Taylor's contention that the average investment per line extension will stay constant at about $730 per customer into the future. Exhibit CCS 1.10R shows mathematically that as additional line extensions are added at the $700 cap, the Company's average investment will decrease. Thus, when rates are set in this case, and the line extension policy changes are incorporated within those rates, the average investment per customer will decrease starting with the implementation of those rates.

The declining investment in the Company's line extensions in the future must be reflected in rates in the current case; otherwise, the Company will receive a windfall with the ratepayers continuing to pay as if the Company were incurring the higher cost per line extension. The Committee urges the Commission to adopt Mr. Larkin's recommendation related to line extensions and to also require the Company to provide data related to dollars the Company will collect from commercial and industrial customers who will be required to pay increased line extension contributions in the future.

COST OF CAPITAL

The issues of the cost of debt and the cost of preferred stock were not contested by the parties, and all parties accepted the Company's proposed cost of debt of 7.231% and the cost of preferred stock of 6.017%. In this case, the issues of the appropriate capital structure and the cost of equity were contested.

Capital Structure

The Company proposes a capital structure consisting of 47.4% debt, 3.8% preferred stock, and 48.8%

common equity. The Committee proposes a capital structure consisting of 47.90% long-term debt, 5.90% preferred stock, and 46.30% common equity. Both of these recommendations are based on the average capitalization ratios of the groups of comparable utilities used by the parties in their respective analyses of the cost of common equity. Both recommendations are based on Value Line data for the end of 1998. The lower common equity ratio proposed by the Committee will result in a lower weighted-average cost of capital, all else equal.

Actually, both the recommendation of the Committee and the proposal of the Company on the capital structure reflect hypothetical capital structures since the Company acknowledges that it would be improper to use the capital structure of PacifiCorp and it states that it is impossible to develop a capital structure specific to the Company's Utah operations. This being the case, the question becomes is one capital structure better than the other or should the Commission in its wisdom adopt a capital structure it believes is proper for rate-making purposes.

The Company's proposed capital structure is supposed to be the average capital structure of utilities with a single-A rating or higher deriving at least 75% of total revenues from the sales of electricity and for which complete and reliable data are available. The Committee's witness, Dr. Legler, based his sample of companies on Value Line's group of electrics with a single-A rating, but he did not further screen his sample for companies with 75% or greater of their revenues derived from the sale of electricity. There are numerous factors that could be used to screen companies for inclusion or exclusion from the list of comparable companies. For example, companies engaged in merger activity could be excluded on the grounds that their stock prices are influenced by the merger activity. Companies decreasing or eliminating their dividends could be excluded on the basis that their dividend yields are not representative, and those reintroducing a dividend will have an extremely high measured dividend growth rate. It is also possible that the fuel mix used by individual utilities may be a reasonable proxy for risk. Dr. Legler simply prefers to take an alternative approach, and make adjustments for disparity between a broad sample of companies and the Company under observation. Not surprising, Dr. Legler's basic sample of companies was larger than Dr. Hadaway's (30 vs. 20).

During the hearing, the Company pointed out that several of the companies in Dr. Legler's sample derived less than 75% of their revenues from the sales of electricity. For example, the Company pointed out Reliant Energy, the parent of Houston Lighting and Power. According to the figures shown in Cross Exhibit No. 27, a single page from a C.A.Turner Utility Reports, Reliant only derived 29 percent of its revenues from the sale of electricity. As was noted, the equity ratio for Reliant was 37.6% according to the Value Line data [see page 342 of the Transcript]. The Company also pointed out that another Company used by Dr. Legler, Northwestern Corp. derived only 5 percent of its revenues from electricity sales according to the C.A. Turner data.

Cross Exhibit No. 27 (the C.A. Turner data) only provides data for combination electric and gas companies and does not provide data for pure electric companies. There are, however, companies on this list that are included in the list of companies used by Dr. Hadaway in his analyses. Not all of these companies meet the 75% of revenues derived from electric sales standard that Dr. Hadaway used. For example, CINERGY does not meet the standard. Therefore, based on the Cross Exhibit introduced by the Company, there is reason to believe that it was not the source of the data used by Dr. Hadaway to construct his sample of companies limited to 75% of more of its revenues from the sale of electricity, and it should not be used as the source of data to challenge the capital structure proposed by the Committee.

The Company challenged the use by Dr. Legler of companies involved in mergers. The Committee is aware of no testimony having been presented regarding the number of companies in Dr. Hadaway’s sample that are involved in mergers. If merger activity is a problem for Dr. Legler's sample of companies, it may also be a problem for Dr. Hadaway's sample. Furthermore, if a Company is to be eliminated from consideration based on capital structure issues, it should also be removed from the analyses leading to a recommendation on the cost of common equity. As will be discussed below, eliminating those companies with a low proportion of common equity in their capital structures (more risky companies based on financial risk) would have the effect of lowering the estimated cost of common equity.

The Committee's Proposed Capital Structure is Reasonable

The Committee's capital structure is reasonable and reflective of the companies used in Dr. Legler's cost of equity analyses. The Committee has not chosen to attempt to pick apart Dr. Hadaway's choice of companies included in the group of companies he considers comparable. The Committee is well aware that no individual Company or group of companies will be exactly comparable to PacifiCorp in all respects. It does believe, however, that its proposed capital structure is reasonable and should be adopted by the Commission.

The Company's Criticism that Dr. Legler's Recommendation does not Reflect the Rise in Interest Rates is Unfounded.

The Company contends that Dr. Legler's recommendation does not reflect the rise in interest rates since he testified in the Company's last case is incorrect. In the Company's last rate case, Dr. Legler's recommendation on the cost of equity was 10.25% which the Committee adopted as its recommendation. In this case, Dr. Legler's recommendation on the cost of equity is 10.5%. Clearly, he has raised his recommended cost of equity, although not by as great an amount as the Company would like. It is the Company's witness, Dr. Hadaway, who has not increased his recommendation. In the last case, Dr. Hadaway recommended a cost of equity of 11.25%, the same rate he is recommending in this case. What is correct, but not acknowledged by the Company, is that Dr. Legler's recommendation in this case is the same rate as adopted by the Commission in the last case. It would seem that the Company would prefer that Dr. Legler use the Commission's last award as the starting point of his analysis. If this is what the Commission would have the witness do, then the Commission's award in the last case should have been the starting point of Dr. Hadaway's analysis, but the Committee can find no evidence that it was.

The Company's witness, Dr. Hadaway used two approaches to estimate the cost of equity, the Discounted Cash Flow (DCF) approach and the risk premium approach. He applied a nonconstant growth version of the DCF model to a group of single-A or higher rated utilities which derive at least 75% of their revenues from the sale of electricity and for which complete and reliable data are available. His risk premium analysis is based on a comparison between allowed returns on equity and Moody's single-A rated utility debt.

Dr. Legler, the Committee's witness, used three approaches to estimate the cost of equity, the DCF approach, the risk premium approach, and the Capital Asset Pricing Model (CAPM) approach. Dr. Legler applied the constant growth version of the DCF model to a broad group of single-A rated utilities. His risk premium approach was based on a comparison of forecasted or forward looking equity estimates with single-A rate public utility debt. He applied the CAPM model in a conventional manner to PacifiCorp, a group of single-A rated electrics, and to Dr. Hadaway's sample of allegedly comparable electrics.

<u>The Company's Use of a Nonconstant Growth Version of the DCF is Based on Unreliable Assumptions.</u>

Dr. Hadaway uses two versions of the nonconstant growth version of the DCF model. Both of these versions of the DCF model produce higher results than the constant growth version used by Dr. Legler. The first version is called "Market Price" DCF model. Under this version of the model, dividends are expected to grow at some assumed rate, and the stock is assumed to be sold a some assumed point in the future. Dr. Hadaway assumes that the stock will be sold in four years at a price based on projected earnings and a price to earnings ratio equal to the Company's current P/E ratio. In short, the Committee finds that the assumption the P/E ratio will be equal to the present level is highly suspect. Using a lower P/E ratio, would have the effect of lowering the forecasted price, and accordingly, the cost of equity. The results of the model that assumes the P/E ratio will remain constant should be disregarded by the Commission.

Dr. Hadaway's second application of the DCF model assumes that the dividend will grow at one rate in the short-term and at another rate, a constant rate, beginning at some point in the future. The short-term growth rate is assumed to apply for years two through five; the transition period is years six through nine; and the long-term constant growth period is assumed to begin in year ten. Dr. Hadaway's application of this model also should not be relied upon. The long-term growth rate is assumed to be 6.2%. Dr. Hadaway states, on page 24 of his testimony, that this growth rate is the average of the individual Company short-term growth rates (4.9%) and the Institutional Brokers Estimation System (IBES) projected growth rate for the S&P 500 (7.5%). He suggests that this rate is consistent with recent and long-term projections of nominal growth in the overall U.S. economy. Obviously, the assumed long-term growth rate will have a significant effect on the return on equity produced by the model. The Committee's primary concern is with the assumption that the long-term growth rate for each and every Company is the same 6.2%. There is no historical evidence that each of a group of twenty companies has increased its dividends at the same rate for any sustained period, and it is highly unlikely that Dr. Hadaway's group of utilities will do so in the future. Furthermore, it is unlikely that the group will increase its dividends at the projected growth rate of the overall U.S. economy.

Although Dr. Hadaway is critical of the constant growth version of the DCF model in his testimony, he did acknowledge during his cross-examination (by Mr. Ginsberg) that the constant growth version of the DCF model does have validity [TR 261]. The Committee also suggests that Dr. Hadaway's affirmation of the constant growth version of the DCF model is based on the results, or Dr. Hadaway's perceived results being consistent with his recommendation of the level of the return on equity [TR 261].

Dr. Legler used the constant growth version of the DCF method. This method has been supported by the Commission. Specifically, in its order in Docket No. 93-057-01, the Commission stated that under this version of the model it is relatively easy to determine the reasons for the differences in results among the witnesses. Based on three measures of dividend growth, retention growth, Value Line projected growth, and historical growth, Dr. Legler found an average DCF return on equity of 10.22% based on average prices over a relatively recent three month time period, and an average DCF return on equity of 10.55% based on stock prices as of December 31, 1999. Based on stock prices somewhat more dated than those used by Dr. Legler, Dr. Hadaway found an average DCF estimate of the cost of equity of 10.2%, about the same as found by Dr. Legler despite differences in their groups of comparables, and methods of arriving at the growth rate. The Committee believes that Dr. Hadaway's analysis supports the DCF results obtained by its witness, Dr. Legler.

Dr. Hadaway also used the risk premium approach to estimate the cost of equity. In this method, Dr. Hadaway compared authorized returns, returns allowed by commissions, with average public utility bond yields by year for the period from 1980 to 1998. There are several problems with this analysis. First, the source of the allowed returns on common equity apparently is Regulatory Research Associates from their publication *Regulatory Focus.* This publication provides average authorized equity returns for "Major Rate Case Decisions" as noted on page 20 of Dr. Hadaway's testimony. We do not know if all decisions are included, if those that are reported are for companies with the same bond rating, if they are only for electric utilities or are other utilities such a telephones included. In short, the average returns may not be comparable, and there is no reason to assume that the average public utility debt yields are appropriate for comparison purposes. Furthermore, Dr. Hadaway only reports the results through 1998, with none shown for 1999. Under cross-examination he acknowledged that the average allowed return for 1999 was about 10.8%, or roughly a full percentage point below the averages he shows for 1998. Also, he acknowledged that the rate he shows for the fourth quarter of 1998 has been revised downward from the 12.03% he shows [TR 281]. After calculating the risk premium for each year from 1980 to 1998, Dr. Hadaway relates the calculated risk premiums to interest rates by using regression analysis. He demonstrates graphically that there is an inverse relationship between interest rates and risk premiums. That is when interest rates are high, risk premiums are low and vice versa.. He uses the slope of the regression line to adjust the average risk premium of 2.79% to current interest rate levels. Based on this analysis, Dr. Hadaway found a current risk premium of 3.98% which he added to the recent single-A cost of debt of 7.79% for a risk premium estimate of the cost of equity of 11.8%. According to his Schedule 5, page 1, the last time prior to 1998 that the risk premium actually was as high as 3.98% was 1986. In short, while interest rate have range from 7.56% to 10.45%, measure risk premium ranged from 2.94% to 3.85% during the period from 1987 to 1997. The Committee does not believe that the historical experience over this recent time period supports the Company's position that the cost of equity using this method is 11.8%.

Dr. Legler used a forward-looking risk premium analysis. Essentially, he compared expected equity rates with current debt costs for each year from 1978 through 1999. To estimate expected returns he used DCF analysis and CAPM estimates. He found a risk premium of 3.01% based on utility bond rates (single-A) for

PacifiCorp and a risk premium of 2.81% for Moody's 24 electrics. Using a bond rate of 8.4% compared with Dr. Hadaway's 7.79%, he found the cost of equity to be in a range from 11.21% to 11.41% based on utility bond rates. Thus, Dr. Legler's risk premium estimate is from about 40 to 60 basis points lower than Dr. Hadaway's even allowing for the higher interest rate.

Applying the CAPM to Dr. Hadaway's Sample of Companies Supports Dr. Legler's Estimate of the Cost of Equity

Dr. Legler also used the Capital Asset Pricing Model to estimate the cost of equity. This method states that the cost of equity to a Company is equal to a risk-free rate plus a market risk premium adjusted for the riskiness of the Company for which the estimate is being made. The adjustment factor is called beta and it is a measure of the volatility of the stock relative to the volatility of the market. Although there is controversy regarding the measurement of beta, one common cited source of betas is Value Line. Even if one were to accept the usage of the Value Line betas, which tend to be on the high-side of possible betas to use, a risk-free rate equal to the long-term U.S. Treasury bond rate, and an historical market risk premium of 8.0% based on a well cited study by Ibbotson Associates, the CAPM estimate of the cost of equity is well below the recommendation of Dr. Hadaway. Based on a risk-free rate of 6.5%, the yield on long-term U.S. Treasury bonds at the time Dr. Legler prepared his testimony, the CAPM estimate for PacifiCorp is 10.10%, 10.66% for Dr. Legler's group of single-A utilities, and 10.74% using Dr. Hadaway's group of comparables. Long-term U.S. Treasury bond rates have decreased since Dr. Legler filed his testimony. The Committee urges the Commission to take into account long-term interest rates. In this case, such updating would serve to underscore the reasonableness of Dr. Legler's recommendation.

Given the Problems with Dr. Hadaway's Analysis, and the Reasonableness of Dr. Legler's analysis, the Committee's Recommended Cost of Equity of 10.5% and Overall Return of 8.68% are very Reasonable.

The Committee is well aware that there is only minor difference in the capital structure recommendations of the Company and the Committee. Adoption of the Company's position on the capital structure with its higher equity ratio would result in a higher overall cost of capital which the Committee believe is unjustified. The Committee does note that if the Commission should adopt the Company's position based on its assertion that Dr.

Legler's group of companies contains some Company which receive a low percentage of their revenues from the sale of electricity, it should adopt a cost of equity without regard to these companies. Such a revision would result in a lower cost of common equity. Theoretically, a higher equity ratio implies lower financial risk. The CAPM is well suited to demonstrate the effect of eliminating those companies with a low level of revenue from electricity sales.

The Committee also recommends that the Commission do as PacifiCorp requested in the last rate case – adjust the rate of return to reflect the quality of management. PacifiCorp has admitted that its management was deficient during 1998, and the return on equity should reflect that.

The Committee respectfully recommends a cost of equity of 10.5% and an overall cost of capital of 8.68% as shown on Schedule 4.19 of Dr. Legler's testimony.

TARIFF CHANGE

Minimum Bill

The Committee asserts that there are two primary mechanisms through which PacifiCorp may recover the fixed costs associated with providing ratepayers the "option" to consume electricity: (1) through a flat energy rate; or (2) through a fixed customer charge. In the former, fixed costs associated with the provision of the "option" to receive electricity (meter, service drop, meter reading, and billing and collecting services) are recovered only through the energy rate, while in the latter customers are charged a flat rate at all levels of usage in order to cover these costs.

The Committee recognizes that at very low levels of energy usage (below 46kWh based on the current energy rate) that revenues collected through the energy rate would be insufficient to cover these fixed costs. If the customer was simply charged a flat energy rate, the Company would only be able to recover between $0-2.70 for 0-46 kWh of usage, respectively (at the current energy rate of .058753). Thus, the Committee recommends that at these low levels the "minimum bill" of $2.75 (the cost of providing these services) *replace* the usage charge. The minimum bill for these customers is greater than what would be collected under the current energy rate. The basis for this recommendation is that the Committee acknowledges that the Company should be able to recover these costs even when energy usage is low.

The second alternative is to collect fixed costs through a customer charge. This recommendation has been made by both the Company and the Division. The Committee objects to the principle of a customer charge because it both confuses and misinforms customers. That position is also inconsistent with past Commission orders in electric rate cases (78-035-14, 79-035-12, 97-035-01) . In those orders the Commission expressed a preference to move away from fixed charges and toward including such charges in the energy rates. The Committee's position is the only position proffered in this case that is consistent with that approach.

RATE SPREAD/RATE DESIGN

There is substantial difference in the various parties spread proposals, and on this issue it is the Division that has taken an uncharacteristically extreme position. PacifiCorp recommends that any change in rates be spread in a way that any one class not receive a change greater than 1 ½ of the jurisdictional average change. The Committee recommends, for the reasons set forth below, that schedules 1, 10, 23, and 25 receive the jurisdictional average change in rates. The Division recommends an increase in rates and that residential schedule 1 customers receive 2.2 times the average rate increase, small business schedule 23 customers receive 1.66 times the average change, and irrigation schedule 10 customers receive twice the average. The Division recommends that large business customers on schedules 6 and 9 receive no increase. Translating this to dollars, the Division recommends that residential schedule 1 customers pick up about 85% of its recommended increase in rates.

The Division may feel that it has good reason for such a recommendation, but asking the smallest customers to pick up 85% of the increase while the largest customers receive no increase on its face borders on being unconscionable. It also flies directly in the face of the Division's long-standing policy of gradualism – a policy it has historically championed and has used in this case on other issues. Loading 85% of an increase on one class of customers, while other classes see no increase whatsoever, violates any definition of gradualism.

All spread recommendations are also based on load research data that has numerous problems. Load research data is designed to be accurate within plus or minus 10% on 90% of the occassions. And the load reasearch in this case does not even meet that test. There are problems with the census data, and problems with calibration that cast significant doubt on the ability to use the load data as the final word on anything. Any errors are automatically assigned to the small customer classes. As pointed out during the hearings, one error found in the data (data that the Company had previously said was error-free) caused a change in the allocation of peak responsibility to the residential class of about 5.5% in one month. [TR 1410:15 - 1411:10] If just one error can have such a significant impact, the results of the study should be looked at with a certain degree of skepticism. As Division witness Townsend succinctly put it: “garbage in, garbage out.”

The Committee respectfully submits that there is not sufficient reliable data upon which this Commission should spread any rate change on a basis other than the average, at least with respect to schedules 1, 23, 25, and 10.

CONCLUSION

Ratepayers deserve rates set on proper costs – no more and no less. PacifiCorp proposes to include a number of costs in going-forward rates that are not proper. Some Company positions are even directly contradictory to its statements to its shareholders and in previous proceedings before this Commission. Whether that is due to new ownership and management we do not know. We do know that 1998 was an unusual year for PacifiCorp. Its management admitted to not doing its job that year. Some adjustments are the result of such inattention by management, and ratepayers should not have such costs built into rates. Other adjustments stand on their own. The Committee believes it has put forth credible evidence on its adjustments, and encourages the Commission to adopt them in setting rates. The Committee also recommends that the Commission reject the very lopsided spread proposal of the Division, and the less lopsided but still heavily weighted against small customers proposal from the Company. Any rate change arising out of this matter should be spread such that the small customers do not receive any greater change than the average rate change.

DATED this 28th day of April, 2000.

By
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Assistant Attorney General

CERTIFICATE OF SERVICE

I hereby certify that I caused a copy of the foregoing Post-Hearing Memorandum of the Committee of Consumer Services, in Docket No. 99-035-10, to be mailed, postage prepaid on this 28th day of April, 2000, to the following:

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