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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF PACIFICORP FOR APPROVAL OF ITS PROPOSED ELECTRIC RATE SCHEDULES & ELECTRIC SERVICE REGULATIONS

DOCKET NO. 99-035-10

MEMORANDUM OF THE DIVISION OF PUBLIC UTILITIES

The following constitutes the Post Hearing Memorandum of the Division of Public Utilities (DPU) in this docket.

I.

INTRODUCTION

At the time the DPU filed its sur-rebuttal exhibits, it recommended an increase of $26,790,439. With the filing of the numerical summary exhibit, the DPU's increase was $27,031,782. These minor corrections are reflected on Attachment 1. Also shown on Attachment 1 is the effect on the DPU's revenue requirement of the request by the Company to file a late filed exhibit. The proposed change of PacifiCorp's amounts to almost $2.5 million. The DPU has reviewed the corrections proposed by the Company and agrees with their calculation. The only issue may be the timing of the request by the Company.

The DPU recommends that this increase be spread pursuant to Exhibit DPU 9.8 SR. This spread was based on a 1998 cost-of-service study utilizing the two evening peaks of the 1997 cost-of-service study. The proportional increase for each schedule shown on Exhibit DPU 9.8 SR is based on the percentage increase necessary to bring each schedule to cost-of-service. The schedules being increased all fall outside of the range of + or - 10% of the target rate of return. The company's proposed spread is based on a revenue increase of $55.2 million or 8.1%. At that level the company proposes to increase Rate Schedule 1 by 12% and also proposes an increase to Schedules 6 and 9. At the DPU's proposed rate increase, no change to Schedule 6 or 9 is proposed. Both Schedule 6 and 9 are within the + or - 10% range of rate of return assuming the Division's two evening winter peak cost of service study. Using the four evening winter peaks which occurred in 1998, both Schedule 6 and 9 fell outside the + or - 10% rate of return range - requiring a *decrease* to move these schedules to cost of service. It appears that 2000 may be a three evening winter peak year because one has already occurred and November and December have peaked in the evening for the past three years straight. Increasing rates for these schedules would effectively increase interclass subsidies. One must recognize that the Company's limitation on the proposed rate increase for schedules to 150% of the average rate increase was based on a significantly higher revenue requirement than what is proposed by the DPU. At the DPU's proposed revenue increase, we did not see the need to limit the rate increase to 150% of the average increase because even with the DPU's proposed rate increase for Schedule 1, customers' rates will still be lower than what they were prior to the 12% rate decrease authorized in the last case. The increase is also lower than suggested using the four evening winter peak cost of service study. We believe that the Commission should have sufficient confidence in the trends stated in the cost of service studies to move classes significantly toward cost of service and not ignore the cost of service studies presented.

This Memorandum will only selectively address the numerous issues outlined in the narrative summary exhibit.

ADJUSTMENTS

1. Time of firm peak load for purposes of jurisdictional allocations. Mr. Powell's Exhibit 4.

Since 1990 there has not been a year other than 1998 that has had four evening winter peaks. Two evening winter peaks (the previous record) occurred in 1997 and 1999. We currently know that 2000 will not have four evening winter peaks. All parties, including the Company, recognize that, at least for class cost-of-service purposes, four evening winter peaks for the test year is enough of an anomaly that cost-of-service studies using peak demand data from prior years were needed to be run in order to modify the 1998 results. The Company, for purposes of revenue requirements, wishes to ignore the fact that the four evening winter peaks for 1998 is an anomaly and needs to be normalized. It is equally important to normalize the revenue requirement for abnormal events as it is to normalize the cost-of-service results for purposes of distribution of the revenue requirement to classes. One determines how much money the Company receives while the other only distributes the revenue requirement among classes. It is no wonder that the Company ignores the effect of the four evening winter peaks when it comes to revenue requirement since it increases revenue requirement in this case. The statistical analysis performed by Mr. Powell clearly show that 1998 is an anomaly.

In reviewing Exhibit DPU 4.3 SR, particularly p. 5 and 6, one can conclude that when we include the Montana adjustment 1998 and 1999 track very well. The Company criticizes Mr. Powell's use of the 1997 SC factor to estimate the 1998 factor. The 1997 weather normalization adjustment is to bring data to what the data would be under normal weather conditions. Use of that normalized 1997 data is the starting point for the 1998 estimated SC factor. In conclusion, all parties recognize that four evening winter peaks has never happened prior to 1998 and did not reoccur in either 1999 or 2000. Mr. Powell's SC adjustment is an attempt to normalize the Utah revenue requirement for the 1998 SC anomaly.

2. Uncollectable accounts.

The proposed adjustment by both the Committee and the Division is intended to accomplish the same purpose, i.e., to exclude the abnormally high uncollectable levels for 1997 and 1998. In 1997 average write-offs were 8.5%. Those write-offs increased to 10.2% in 1998. A more consistent 4% write-off reflects more normal conditions. In the last rate case the Commission excluded 1997 accruals. We believe that 1998 accruals are as abnormal as the 1997 accruals and should also be excluded. In this case the Company seems to acknowledge an even greater problem with collections than the last case. An internal task force was established to correct numerous collection problems. In addition, an outside consultant was hired to help the Company solve its collection problem. The reasons the Company gives for including 1998 in the average three year calculation of uncollectables is similar to the reasons given for including 1997 in the last rate case. They argue that personal bankruptcies and the growth in customers, increases the growth in uncollectables. Those reasons were taken into account by the Commission when it rejected the inclusion of 1997 in the last rate case. The adjustment in the last rate case was $1.292 million. The adjustment in this rate case is $1.366 million. Allowing the Company to include 1997 and 1998 in calculating an average would essentially negate the views expressed by the Commission in the last rate case, that 1997 was an anomaly. That evidence equally applies to 1998.

3. The SMUD Adjustment.

With the acceptance of the DPU's proposed adjustment to the Sacramento Municipal Utility District ("SMUD") wholesale contract, the Company has accepted an imputation of revenues to reflect fair compensation for service. A number of ways to show what the appropriate cost to impute were presented. The DPU used an Idaho stipulation which imputes revenues based on approximately $19.00 / MWH. This reflects a stipulated agreement between Idaho and PacifiCorp regarding the value of non-firm power. The Committee bases its SMUD adjustment on an Oregon stipulation and filings made by the Company in Oregon in 1997 and 1998. The imputation in the Oregon stipulation roughly doubles the DPU's adjustment and is based on a Southern California Edison ("SCE") long term firm contract originally signed the same year as the SMUD contract. Mr. Burrup indicated that he did not use the SCE contract since it was renegotiated and was not contemporaneous with the SMUD rate. Which number is correct? Mr. Burrup acknowledged that $23 / MWH would also constitute a reasonable number for a SMUD adjustment. That number represents the average firm sales price of COB and Pale Verde Electricity Price Indexes published in the Wall Street Journal in 1998. This is a firm price and not a non-firm price such as in Idaho, therefore addressing the CCS concern on the Idaho stipulation.

4. Organizational Costs.

At the time of the PacifiCorp / Utah Power & Light merger, the order required organizational costs be split 50 / 50 between ratepayers and shareholders. Excluding the costs from rate base and amortizing it over 15 years was a convenient way to split the cost 50 / 50. No mention was made that the 15 year period was selected as a reasonable comparison to the flow of merger benefits to Utah. In fact, the only contemporaneous evidence presented is cross-examination exhibit 16, which is Mr. Burrup's memorandum proposing the 15 year amortization period to the Commission. That memorandum makes no mention that the 15 year amortization period had anything to do with the flow of merger benefits to Utah. The Company is proposing to decrease the amortization to 3 years to coincide with the Commission's allocation order. The Company is attempting to change the amortization set by the Commission many years ago arguing that it now needs to coincide with the Commission's decision to go to roll in. Although the net present value of the Company's calculation is the same as the current amortization, the effect is to increase revenue requirements today. The Commission should not attempt to second guess the reason the Commission established the 15 year amortization. The attempt to amortize the cost more rapidly is only an attempt to try and increase rates today unnecessarily.

5. CSS Software Maintenance Contract (DPU 4.2 SR).

In the stipulation in the last general rate case, 1/3rd of the investment of the CSS software was removed from the test year. In addition, 1/3rd of the cost of the maintenance contract that the Company issued for the specific purpose of the CSS system was also removed in the stipulation in the last general rate case. In this case, the Company removed 1/3rd of the investment but requested inclusion of the maintenance contract. As in the last case, the DPU proposes to exclude 1/3rd of the cost of the specific maintenance contract used for the CSS system. There does not appear to be any logical reason for the Company to exclude 1/3rd of the investment in the CSS system while allowing the maintenance contract developed specifically for the CSS system into rates when such amount was specifically excluded in the last case.

The CCS proposes not only to exclude 1/3rd of the cost of the contract, but also proposes to exclude 1/3rd of the internal maintenance cost associated with the CSS system. The Company's response is to indicate that CSS is mainly only being used for regulated purposes. This, however, does not address the fundamental issues surrounding the investment for CSS and the specific contract (now canceled) used to aid in implementing the CSS system. One appears to go with the other. No attempt is being made by the DPU to exclude all of the maintenance associated with computer systems. Only the amount associated specifically with the implementation of the CSS system is being removed.

6. Account 903 Allocation Factor (DPU 4.3).

Prior to 1997, most Account 903 expenses were directly assigned to the states. Only 20% of the costs were allocated. In 1997, the business centers were established, that were designed to provide the same service, albeit in a better way, than the previous method of providing customer service. Therefore, after 1996, 80% of the costs are now required to be allocated rather than directly assigned. It is this allocation factor that the Account 903 dispute involves. When we cannot directly assign costs as we could previously, we look for a cost causal relationship in the method of allocating those costs. The Company objects to looking at 1991 - 1996 costs. However, their objection misses the point. Looking at the 1991 - 1996 costs was to determine if, in those years, there was a valid bases to allocate costs on a CN factor. If no such relationship exists then why should current Account 903 costs be allocated on the basis of CN. No such relationship could be shown for that historical period.

In the absence of a clear cost causal relationship between the number of customers and Account 903, a general allocator was chosen for this case to allocate the Account 903 cost until more data is available. Cross-examination Exhibit 17 shows that total Company expenses presented in JKL2R have gone up 12.2% while for Utah the same expense has increased 23.2%. Customers, on the other hand, have increased only 14.6% in Utah over that time period, and for the entire Company have increased 9%. The explanation that customer growth is the cause of the increased cost to Utah for customer services appears flawed. Further analysis appears to be necessary.

What appears to be happening is that as a result of the creation of the customer service centers, which were to save everybody money, Utah gets allocated a disproportionally higher portion of those costs over the previous allocation scheme. That disproportionally higher cost being allocated to Utah does not appear to be based on a cost causal principle. Mr. Powell’s proposal is to use a general allocator as a temporary way of allocating these costs until further analysis can be done to demonstrate if CN has a cost causal relationship.

7. Non-regulated Business Postage (DPU 4.5 R).

The fundamental issue being presented is whether incremental costs or fully distributed costs should be assigned to affiliated non-regulated businesses when those businesses are using regulated services. The example provided and the proposed adjustment made by the DPU relates to postage on bills where non-regulated information is provided in the bill to the customer. There are disputes surrounding what the cost would be on a fully allocated basis. Also, there are disputes surrounding what the market price would be. Hopefully in this docket, principles can be established that can guide future adjustments where the regulated business is providing services to its non-regulated businesses. The DPU urges the Commission to adopt the principles established in the NARUC guidelines for cost allocations and affiliated transactions provided in Exhibit DPU 4.4. That guideline provides:

> Generally, the price for services and products provided by the regulated entity to its non-regulated affiliates should be at the higher of fully allocated costs or prevailing market prices.

The DPU believes that the Commission in an earlier docket (91-049-13, cross 62) establishes the principle that fully embedded costs should be the method to allocate cost where the regulated utility provides both regulated and non-regulated services. US West Communication's ("USWC") regulated operations sells voice messaging service (VMS). The question presented in the order is how those costs should be allocated between the regulated and non-regulated functions. The order provides:

> Part 64 is a fully distributed cost allocation method designed to assure that costs and investments related to FCC non-regulated services are appropriately separated from those of regulated services. . . . The FCC has recently strengthened Part 64 to assure that the regulated utilities ratepayers do not subsidize its provision of non-regulated services.

The issue being presented to the Commission is if the principles established by the FCC and adopted by this Commission for USWC non-regulated services will be applied to PacifiCorp. Clearly the use of embedded cost for separating regulated and non-regulated functions in the telephone industry has become commonplace. We urge the Commission to adopt those principles here.

8. Y2K Expenses.

The argument not to amortize Y2K expenses in 1998 appears to revolve around the argument that somehow they are being penalized by spending the money on Y2K. Under normal conditions, an expense of this magnitude that has already ended would clearly be amortized over some future period. The unamortized portion is included in rate base so the Company is not penalized. Why should Y2K be treated differently? The Company argues that the Commission allowed the 1997 expense in rates without any amortization. The 1997 expense levels were significantly lower than the 1998 levels.

With the amortization of the 1998 Y2K expense, the Company is assured of recovery of those costs over a reasonable period of time. If a 1999 test year is utilized in a future rate case, a similar amortization could occur for the 1999 expense level. To not amortize any of the Y2K expenses builds into rates millions of dollars of expenses that will never occur again. Clearly, that is an inappropriate response. A 5 year amortization is consistent with other amortizations proposed by the DPU for such things as computer write-off, software write-off, and Glenrock. Even the Company's 3 year amortization that they utilize for the above listed items would be better than building in rates the abnormally high and one-time Y2K expense.

9. WAPA.

There is no current Western Area Power Administration ("WAPA") adjustment built into rates. There are two WAPA contracts being addressed. One represents the Utah Power & Light system. The other represents the CP National system that Utah Power acquired in the early 1980s. For whatever reason, no WAPA adjustment has been made even though in 1982 in Docket 82-035-13 (cross 52), the Commission clearly established a policy that there should be an adjustment for the CP National WAPA contract. Mr. Powell testified that the principles established in that order equally apply to the Utah Power & Light contract.

In Docket 82-035-13, the Division proposed an adjustment to test year wheeling revenues to off-set the deficiencies between the cost-of-service and the wheeling revenues received from the WAPA contract. The Company, for reasons similar to today, stated that the transaction taken as a whole is advantageous to the Company and customers. The Commission, in reaching its decision, states:

> The purpose of similar adjustments in previous CP National cases has been to avoid subsidy of non-jurisdictional preference customers by Utah retail ratepayers. The assumption of this obligation by Utah Power upon its purchase of the CPN system does not change this reasoning. 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 the transmission investment and expenses between retail customers and non-jurisdictional preference customers.

It is unclear on this record why this adjustment has not been made in previous Utah Power & Light rate cases. It seems that the Commission did provide a policy statement in 1982 that an imputation of revenues to current wheeling rates is appropriate for the WAPA contracts. One might argue under the principles established in Salt Lake Citizens Congress v. Public Service Commission (charitable case) that the company had an obligation to at least make the adjustment on the CP National portion of the WAPA contract or at least bring forth in a clear way the proposal to modify the PSC policy established in the 1982 case. It appears the Company never did that over these many years. In any event, the Commission should reestablish those principles in this case and make the WAPA adjustment proposed by the DPU and CCS.

The only relevant evidence the Company presents on this issue is to point out that the transmission system has been a valuable resource to Utah. No one doubts that. However, a fixed price contract for a 60 year period with no escalations built in is not reasonable.

Utah has chosen a system of revenue credits. As a result, Utah is expected to pick up the cost of a below-cost contract. It would not be expected to pick up those costs if separate jurisdictional allocations between wholesale and retail occurred. Without such an allocation existing, the Commission must evaluate the reasonableness of wheeling and wholesale contracts to make sure that Utah retail customers are not being asked to subsidize wholesale customers. The Commission, in 1982, found that this type of imputation was necessary to avoid "a subsidy of non-jurisdictional preference customers by Utah retail ratepayers." The Commission should reestablish that principle today.

10. Computer Software Write-Down, Computer Mainframe Write-Down, Re-Engineering Costs SAP and Dave Johnson Coal Mine Write-Off.

In the last general rate case (97-035-01) the Commission ruled that the mainframe write-down and the software write-down were both post-test year adjustments. Re-engineering was not allowed as an expense because "benefits of PacifiCorp's re-engineering program begin with the installation of SAP software . . . which will not be placed into service until 1998." The only event that occurred in the 1997 test year was the write-off of the old software and mainframe computer for purposes of their financial books. The order recognized that the old computer would not be replaced until 1998. Further, the order recognized that the old software would not be replaced until SAP began being installed in 1998. At the time of the 1997 rate case, PacifiCorp requested amortization of the old software and computer over a three year period. As an alternative, the Company indicated they would agree to a five year amortization of the old computer and software. In this case, PacifiCorp is requesting a three year amortization of the software and computer system while agreeing to a five year amortization of the re-engineering cost. Unlike the last docket, the DPU has recommended that the amortization of the software and computer system begin in this test year. In addition, the DPU has recommended that the amortization of the re-engineering costs begin in this test year. We recommend that both be amortized over a five year period. The question being presented to the Commission is when amortization of events such as these should be allowed into rates. Should it be when the event actually occurs, i.e., when the mainframe computer is taken out of service? Should it be when the benefits begin to occur from re-engineering and installation of the SAP system, or not until those benefits equal or exceed the cost? The DPU believes that with the beginning of the benefits associated with the installation of the SAP system the amortization of the software, mainframe computer, and re-engineering should begin in this test year.

The mainframe computer was clearly retired in the test year. Second, the software was used during the test year although it began to be replaced by SAP at least in certain locations. Benefits associated with re-engineering and the new computer system and software began to occur in 1998. There is also no doubt that the benefits associated with the SAP system and the replacement of the old software will increase in 1999 and 2000. At what point should the amortization of the old software and computer begin? At what point should the Company begin to recover re-engineering costs? The DPU believes it is when the benefits associated with those projects <u>begin to</u> occur, i.e., 1998.

The Commission’s Order on Rehearing in 97-035-01 issued April 13, 1999, stated in granting rehearing on re-engineering that “it is our intent that recovery should begin coincident with ratepayer benefit.” This beginning of recovery of re-engineering cost and the amortization of the computer hardware and software is coincident with the beginning of benefits and is consistent with the Commission’s order in 95-049-05. In that case, the Division recommended that recovery of the cost incurred by the Company for re-engineering should be deferred until such time as those benefits can be ascertained, matched with the cost, and then off-set against the cost of re-engineering. In other words, as applied to this case, re-engineering and the amortization of the old software and computer would be deferred until the benefits match the cost. In rejecting the Division's proposal, the Commission stated "we have consistently followed a policy of attempting to match revenue, expenses and investments wherever possible. It would be unreasonable to allow recovery of all re-engineering cost incurred in 1994 as it would distort the results of the test year. . . . we commend the Division for its proposal to match the cost and benefits of re-engineering but believe it to be unworkably complicated. It appears to be an open-ended proposal which would require monitoring for some years into the future."

In this case we believe that benefits have begun to occur in the test year. The computer mainframe system was retired. The computer software system, although used during the test year, began to be replaced with the SAP system. Benefits associated with the SAP system and re-engineering began to occur during the test year. These facts, we believe, are all undisputed. Some would argue that the benefits are meager and the amortizations should not begin to occur. The DPU believes that the Commission, in following its Rehearing Order in the last rate case and the US West re-engineering order, will conclude that the amortizations should begin in this test year when benefits have begun to occur.

If the amortizations of the hardware and software begin in this test year, the DPU urges the Commission to make those amortizations consistent with the five year amortization period required in the US West re-engineering order and agreed to by the Company in the last general rate case.

Glenrock, on the other hand, did not close in 1998. It did not close until October 1999. In the last rate case, the DPU took the position that the amortization of the coal mine closure cost and the amortization of the assets should begin when savings from the mine closure begin. At that time, the DPU assumed that these savings would not occur until the mine actually closed. As a result of mine operation plans during the test year some savings have occurred. In addition, final reclamation costs associated with the mine began in the test year. Actual cash expenditures have occurred in this test year. It is not just the recovery of the unrecovered mine asset. The question is when should the amortization of the asset and the recovery of reclamation costs occur. Under normal conditions, when the mine closed the asset would have been totally depreciated. Under normal conditions, reclamation costs would have matched the beginning of reclamation so actual dollars were available to pay for reclamation. This, however, is a case of early closure of a mine. The DPU has consistently supported the closure of this mine. Significant savings ($15 million per year) will occur when the coal is replaced. The beginning of those savings has occurred in the test year. As a result, the DPU has supported the beginning of the amortization of the mine closure costs. We do not believe that it needs to wait until the full coal supply has been replaced.

As with the computer software, mainframe and re-engineering, the DPU believes that these costs should be amortized over a five year period.

11. Condit Plant Depreciation.

The Stipulation and Order in Docket 98-2035-03 and U.C.A. 54-4-24 make it clear that retroactively applying the depreciation rates established in the Order in 98-2035-03 to the 1998 test year would violate both the Stipulation and 54-4-24. The Stipulation clearly provides that the rates included in the Stipulation would not go into affect until April 2000. Condit was part of the Stipulation. 54-4-24 states that companies cannot change depreciation rates until approved by the Commission. Since the order changing the condit depreciation rates did not occur until the order in the depreciation case was issued on January 6, 2000, the Company cannot apply the rate back to a 1998 test year. The Company points out that absent an increase in the condit depreciation rates at this time, the rates will need to be increased dramatically when the next depreciation study is performed in 2002. At the time the Stipulation was entered into in December 1999, information as to the condit dam closure and removal costs was as available then as it is now. The parties agreed that those rates would not take affect until April 2000. No exception was made for the condit dam. No exception should occur now.

12. Wholesale Sales for Resale Revenue Imputation and Net Power Cost.

Utah has adopted a system where all revenues and costs associated with non-jurisdictional sales are included in the revenue requirement calculation for the State. In other words, other than the cost allocation between the retail states, no costs are allocated to a jurisdiction whose responsibility is to cover the non-jurisdictional wholesale sales. Instead, the costs are all present in the Utah revenue requirement off-set by the revenues that have been calculated through the PD MAC model, or otherwise, for that test year. The contracts for these sales are not subject to approval by the Utah Commission since we have no control over the contracts. During a test year, it is important to build into rates revenues that represent a reasonable and normal level of net revenue credit from wholesale services. In order to accomplish that purpose, an imputation of revenue was accepted by the Company for the SMUD contract. Other imputations include: increased revenue imputation for WAPA contracts, imputation of long term firm wholesale contracts, and modifications to short-term firm and non-firm sales and other adjustments in the net power cost calculations from PD MAC.

A review of Exhibit DPU 9.14 SR revised, shows the importance of imputing revenues from these contracts and properly making necessary adjustments to PD MAC. Column 1, entitled PD MAC ($33.649 million) is what PacifiCorp proposes to build into rates. By viewing the actual 1998 results, one can see that the Company is proposing to build into rates even less than the actual results for the year. The column entitled PD MAC R shows that adjustments to the long term firm wholesale contracts proposed by the DPU including SMUD and WAPA and other net power cost adjustments add up to a reasonable level of revenue credits in comparison to actual 1998 costs and to net revenue credits in the past.

The Division is proposing to impute revenues to 6 long-term firm sale for re-sale contracts. The purpose of this adjustment as stated previously is to hold firm ratepayers harmless from long-term firm wholesale contracts which earn less revenues that it costs to serve these contracts, and to insure that for the 1998 test year a reasonable level of revenue credit is reflected in retail rates. Avoided costs filed in Utah at the time the contracts were signed shows that the marginal generation cost with the sale for resale credit plus transmission losses for 1998 were higher than the revenues earned from these contracts in 1998. The DPU asserts that the prices in these contracts more reflect short-term non-firm prices prevailing at the time the contracts were signed than PacifiCorp's own longer-term marginal cost. The actual marginal cost for one MW of power in 1998 was $24.89.

Both the Company and the DPU appear to support the use of avoided cost or marginal cost for determining if these contracts are profitable than embedded cost. However, the DPU believes avoided cost analysis filed in Utah should serve as the basis for determining if these contracts cover costs. We should not be asked to base our decision on some other state's evaluation of avoided costs.

Exhibit DPU 9.14 SR revised shows that 1998 was the worst year on record for the Company for the net revenue credit on a comparative basis. The adjustments to short-term firm and non-firm sales recommended by Mr. Falkenberg normalized losses incurred by PacifiCorp in 1998 and make greater use of actual data in order to better reflect a reasonable and normal level of revenue credit. Even though 1998 may have been a normal year for hydro conditions, it was not a normal year for PacifiCorp's performance in the short-term market. We should not be building into rates a net power cost with revenue credits at a level inconsistent with past levels of revenue credits.

13. Line Extension Policy.

As in the last case, the Company is proposing to change its line extension policy tariff. The DPU supports these changes. The main issue being discussed here is if there should be a revenue requirement adjustment to reflect the implementation of a new line extension policy. The Committee proposes such an adjustment. The DPU opposes that an adjustment to revenue requirement in this case is necessary. Although in the last general rate case, the DPU supported a revenue requirement adjustment for the implementation of this line extension policy, it cannot support one today. The Company will obviously collect more money from new customers than it did in the past. This, however, only means it will have to invest less money from other sources in making the line extension investment necessary to serve these new customers. Over time the average Company investment per customer will decline. Thus, as Mr. Larkin pointed out, average rate base will also decline. This decline in rate base, however, will not occur immediately. The decline in rate base will occur, all else being equal, over a period of years. This reduction in rate base will have the effect of, all else being equal, reducing future rates. To make a revenue requirement adjustment now would be an attempt to capture some of those future savings which will flow through to customers naturally over time through a reduced rate base. As was stated by Mr. Mower, the DPU attempted to mathematically show that the Company would receive a direct rate making benefit from the change in the line extension policy. The Division was unable to make that finding that a direct rate making benefit would inure to the Company in this rate case absent an adjustment. Therefore, it proposed no revenue requirement adjustment.

DATED this ________ day of April, 2000.

By
Michael Ginsberg
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CERTIFICATE OF SERVICE

I hereby certify that I caused the foregoing Memorandum of the Division of Public Utilities to be served upon the following persons by mailing a true and correct copy of the same, postage prepaid, to the following on the ________ day of April, 2000:

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