Docket 01-035-01
Division of Public Utilities
Ronald L Burrup
DPU Exhibit No. 1.0

In the Matter of the Application of PacifiCorp for Approval of its Proposed Electric Rate Schedules And Electric Service Regulations	)))))	**DOCKET 01-035-01**

PRE-FILED DIRECT TESTIMONY

OF RONALD L. BURRUP

FOR THE

DIVISION OF PUBLIC UTILITIES

DEPARTMENT OF COMMERCE

STATE OF UTAH

JUNE 4, 2001

Q. PLEASE STATE YOUR NAME, BY WHOM YOU ARE EMPLOYED AND YOUR BUSINESS ADDRESS.

A. My name is Ronald L. Burrup, I am employed by the Utah State Department of Commerce, Division of Public Utilities. My business address is PO Box 146751, Salt Lake City, Utah 84114-6751.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS DOCKET?

A. My purpose is to introduce the Division's Summary Exhibit showing the calculation of the revenue requirement for this test year. I also propose several adjustments to the revenue requirement.

Q. PLEASE LIST THE OTHER REVENUE REQUIREMENT DIVISI0N WITNESSES.

A. DPU witness 2.0 is Mr. Tom Peel. He will discuss accounting adjustments related to pensions, deferred income taxes, and the sale of Centralia.

DPU witness 3.0 is Ms. Mary Cleveland. She will discuss issues relating to affiliate interests, SAP, and changes in revenue during the test year.

DPU witness 4.0 is Mr. Carl Mower. He will discuss amortization of software.

DPU witness 5.0 is Mr. Paul Mecham. He will discuss incentive compensation.

DPU witness 6.0 is Dr. William Powell. He will discuss the cost of capital.

DPU witness 7.0 is Mr. Mark Flandro. He will discuss tariff changes.

DPU witness 8.0 is Ms Rebecca Wilson. She will discuss power costs.

DPU witness 9.0 is Mr. Randy Falkenberg, he discusses power costs.

DPU witness 10.0 is Mr. Philip Hayet, he also discusses power costs.

Q. Q. PLEASE EXPLAIN THE DIVISION'S EXHIBIT NO. DPU 1.1

A Exhibit No. DPU 1.1 is the Division's Summary Exhibit, it contains 11 pages. The first is a listing of each Division proposed adjustment. In some cases a Division adjustment is compared to a PacifiCorp adjustment, others are new proposed adjustments. Each adjustment is quantified and the Division's sponsoring witnesses name is shown. Line 46 is the total of all adjustments. Line 47 is an estimate of the change in revenue requirement resulting from changes in allocations, cost of debt, cash working capital and interest synchronization.

Line 48 is the calculated change in revenue requirement obtained by subtracting the total adjustments from PacifiCorp's requested rate increase (line 1). Line 49 is the revenue requirement change produced by the model. These two figures are intended to show that the inputs to the model are accurate. The model results is more accurate than the sum of the adjustments.

The second page is the Division's cost of capital (used in the model) compared to the filed cost of capital. It has updated costs of debt and preferred through December 31, 2000, and includes one Division adjustment shown on the page.

The third page shows the Division's allocation factors. There are three proposed changes in allocation factors. They are identified later in my testimony. The fourth through eleventh pages are the model results. The first column is the Division's unadjusted results, followed by the adjustments, and finally the Division's adjusted results and revenue change. There are approximately 100 adjustment shown in separate columns on the following pages.

Q PLEASE DESCRIBE THE ADJUSTMENTS THAT ARE IN THE REVENUE REQUIREMENT MODEL.

A. The Division has included three types of adjustments in the model: Allocation changes, accounting changes and cost of capital changes.

The three allocation changes are, a correction to the Oregon November 1999 weather normalization loads. (DPU witness Rebecca Wilson), the removal of Brigham City loads and revenues from the Utah jurisdiction to the FERC jurisdiction (DPU witness Rebecca Wilson), and the change of an industrial customers loads and revenues from the Wyoming jurisdiction to the System allocation. (DPU witness Mary Cleveland).

The allocation changes were put into the model first to develop the Division's allocation factors. The Division's accounting adjustments were input next. The Division used Dr. Jim Logan's model to allocate and calculate the revenue requirement. There are approximately 60 company adjustments and 40 Division adjustments. Obviously this involves a lot of calculations. Although the Division is not aware of any errors in our calculations at present, as we become aware of errors they will be corrected.

In preparing the summary exhibits, I observed a discrepancy in the sales for resale and purchase power accounts between the amount recorded in the September 2000 Monthly Financial and Operating Report and the September 2000 Semi-Annual Report. We have called this to the attention of the Company.

Q. WHAT ACCOUNTING ADJUSTMENTS THAT YOU ARE PROPOSING?

A. The issues I address are:

Exhibit No.	Issue	Approximate Amount
DPU 1.0	Testimony of Ronald L Burrup	
DPU 1.1	Division's Summary Exhibit	
DPU 1.2	Witness qualifications	
DPU 1.3	Update customer deposits and interest expense	$ 42,000
DPU 1.4	Abandoned assets under construction	$ 32,000
DPU 1.5	Trojan plant disallowance	$ 45,000
DPU 1.6	Cholla assets under construction	$ 30,000
DPU 1.7	Blue Sky program adjustment	$ 160,000
DPU 1.8	Preferred unsecured debt costs	$ 200,000
DPU 1.9	Dave Johnston coal costs	$ 266,000
DPU 1.10	Hunter coal stockpile	$ 366,000
DPU 1.11	Non-utility amortization	$ 562,000
DPU 1.12	Correct construction write-offs	$ 1,427,000
DPU 1.13	Property insurance reserves	$ 1,275,000
DPU 1.14	Add QUIPS payments to interest true-up	$ 4,078,000

DPU 1.15	Adjust Utah distribution expense	$ 7,744,000
DPU 1.16	Customer Service Costs per Customer	
DPU 1.17	Lead-lag calculation - Utah jurisdiction	

I also discuss the SAP audit, the Wyodak coal contract, Account 903 allocation, Jim Bridger mine accounts receivable, and the sale of hydro-electric facilities.

Q. PLEASE EXPLAIN EXHIBIT NO. DPU 1.2.

A. This is a description of my qualifications.

UPDATE CUSTOMER DEPOSITS AND INTEREST EXPENSE

Q. PLEASE EXPLAIN EXHIBIT NO. DPU 1.3.

A. In the original filing PacifiCorp used estimates of the amount of customer deposits and interest paid on customer deposits. Exhibit No. DPU 1.3 updates the estimates with actual September 2000 figures. This adjustment reduces revenue requirement by $42,000

ABANDONED ASSETS UNDER CONSTRUCTION

Q. PLEASE EXPLAIN EXHIBIT NO. DPU 1.4.

A. This adjustment reverses part of PacifiCorp's adjustment 8.15.2. In this adjustment PacifiCorp removed the cost in rate base of abandoned projects at Hunter and several hydro units. Then as part of the same adjustment amortized the write-of over three years in cost of service accounts. The company chose not to complete these projects after starting them. These projects provided no benefit to Utah customers. I recommend they not be charged to customers. This proposed adjustment removes the three year amortization from the cost of service. The impact is to reduce Utah rates by approximately $32,000.

<u>TROJAN PLANT DISALLOWANCE</u>

Q. PLEASE EXPLAIN EXHIBIT NO. DPU 1.5.

A. PacifiCorp is a part-owner of the Trojan Nuclear plant located near Portland. The plant developed maintenance problems, and the owners (the majority owner is Portland General Electric) received permission from the SEC and FERC to close the plant early and amortize their unrecovered investment over the remaining life of the nuclear license. The amortization ends in 2011.

After the plant's closure, the Oregon Public Utility Commission (OPUC) reviewed the prudence of plant maintenance and determined that a portion of maintenance costs should be disallowed. A portion of the disallowance applied to PacifiCorp.

Under the prior “Accord” interstate allocation method, only a small part of the Trojan investment was allocated to Utah. This made the OPUC adjustment too small to make in Utah. However, under the Rolled-In allocation method, the amount allocated to Utah is 37%, significantly larger. This adjustment, which is made in each rate case by the OPUC, removes the disallowed portion of Trojan investment from rates. Although this Commission has never reviewed the prudence of Trojan, I believe the Utah Commission should make a similar adjustment based on the OPUC review. Exhibit No. DPU 1.5 is an approximation of the revenue impact, a more precise calculation will be provided later. This reduces the Utah revenue requirement by approximately $45,000.

CHOLLA ASSETS UNDER CONSTRUCTION

Q. PLEASE EXPLAIN EXHIBIT NO. DPU 1.6.

A PacifiCorp made an adjustment 8.15.1 to remove the write-off of preliminary engineering and feasibility studies related to the construction of combustion turbines (CT) under the Cholla purchase agreement. The company adjustment then amortized the write-off in rates over the remaining life of the Cholla plant, 16 years. In 1995 PacifiCorp decided not to build the CT's. These costs remained in construction work in progress accruing Allowance for Funds Used During Construction (AFUDC) until they were written off in 1999.

There are two reasons these costs should not be recovered from customers. First they did not result in any useful plant, and second, the utility has some obligation to bring costs forward for recovery in a timely manner. These costs could have begun amortization in 1995, but instead they accrued AFUDC each year since 1995. For these reasons, I do not believe it is appropriate to recover these costs from customers. This adjustment reduces Utah revenue requirement by approximately $30,000.

BLUE SKY PROGRAM ADJUSTMENT

Q. PLEASE EXPLAIN EXHIBIT NO. DPU 1.7.

A. This adjustment removes the revenues and expenses related to the Blue Sky program from the rate case. Blue Sky is a voluntary program where customers purchase blocks of wind-generated power by paying $2.95 per month for each 100 kWh block. The participants fund the cost of the program. Since the program is self funded, its revenues and costs should not be in the revenue requirement. This adjustment removes Utah revenues of $7,607 and Utah expenses of $167,115. The impact of this adjustment is a reduction of $160,000.

PREFERRED UNSECURED DEBT COSTS

Q. PLEASE EXPLAIN EXHIBIT NO. DPU 1.8.

A. At the time of the ScottishPower/PacifiCorp merger, PacifiCorp asked preferred shareholders to increase the total debt limit by $5 billion. In order to obtain approval from a majority, PacifiCorp paid each share holder who returned a vote, $1 per share. The total costs were $3.4 million, which is included in the embedded cost of debt calculation, and being amortized over 5 years. Adjustment DPU 1.8 removes this cost from the debt calculation.

Total long-term debt as of December 2000 was $3 billion. Total capitalization is $7 billion. The yearly construction budget is funded mostly from depreciation, not through additional debt or equity. It is unlikely customer growth would require $5 billion in additional debt at any time in the foreseeable future. This amount of additional debt might be needed for mergers or acquisitions, but not for continued reliable electric service. It is not appropriate for the company to recover these costs from customers. The OPUC staff is proposing a similar adjustment. The impact of removing this from the cost of debt is approximately $200,000.

DAVE JOHNSTON COAL COSTS

Q. PLEASE EXPLAIN EXHIBIT NO. DPU 1.9.

A. The Glenrock mine supplied coal to the Dave Johnston plant until closed in September 1999. During the test year, the plant was supplied by coal from outside sources. The company witnesses state that Glenrock costs were removed from the test year. Exhibit No. 1.9 shows PacifiCorp's coal normalization adjustment for Dave Johnston. October 1999 coal costs were $9.90 per ton. In all other months of the test year the coal costs were between $6.68 and $7.30 per ton. A footnote at the bottom of the company's Glenrock work paper explains why October costs were higher than normal. It states:

> The $/ton in Oct-99 is higher. This is due to the closer (sic) of the Glenrock Mine – final accounting entries were made to

close out the accounting records related to coal production[1].

This indicates that Glenrock mine costs were not excluded. I recommend that the coal costs for October be removed and replaced with the average cost per ton for the other months. Exhibit No. DPU 1.9 also shows the monthly costs per ton, and how the adjustment was calculated. This adjustment reduces fuel costs by $266,784. The lower fuel costs are included in the power cost normalization and not included as a separate adjustment amount. Exhibit No. DPU 1.9 is intended to show the calculations only.

HUNTER COAL STOCKPILE ADJUSTMENT

Q. PLEASE EXPLAIN EXHIBIT NO. DPU 1.10.

A. The closure of the Trail Mountain Mine in April 2001 caused coal inventories to be excessively high at the Hunter plant during the test year. Exhibit No. DPU 1.10 shows Hunter plant inventory by month. From October 1999 to September 2000, inventory increased almost three times, from 592,982 tons to 1,503,034 tons. The mine closure that caused the increased inventory is a non-recurring event, its costs should not be built into base rates. This proposed adjustment reduces the inventory level to the company's budget levels. Coal costs at the Hunter plant will be lower under the new SUFCO contract. Since this occurs outside of the test year, it is not reflected here. If adopted, this adjustment will reduce

1 PacifiCorp Dave Johnston fuel normalization calculation worksheet.

revenue requirement by approximately $366,000.

Q. DID YOU PROPOSE AN ADJUSTMENT TO THE HUNTER COAL STOCKPILE IN THE LAST RATE CASE?

A. Yes, I recommended lower inventory levels for this plant because they were above a prudent level. The company responded that to reduce inventory levels would increase the price per ton of the coal because fixed costs would have to be spread over fewer tons. The Commission agreed with the company's position.

Q. HOW IS THIS INVENTORY ADJUSTMENT DIFFERENT?

A. The current high inventory level at Hunter is caused by a non-recurring event. Coal inventory can be controlled by PacifiCorp by scheduling deliveries from the coal supplier. The price is set by long term contract. It does not appear reasonable to include the higher inventory in rate base based on a one time event.

NON-UTILITY AMORTIZATIONS

Q. PLEASE EXPLAIN EXHIBIT NO. DPU 1.11.

A. Amortization expense (Account 404), and Miscellaneous Deferred Debits (Account 186), contained some non-utility related costs. This adjustment recommends that 4 items be removed. Costs for the 1998 Business Strategy Policy were included in Account 186. The 1998 Business Strategy was the return to basics plan. The plan of being a world wide energy supplier was scrapped and replaced with a renewed focus on domestic electric operations. Customers should not pay for development of this plan.

Account 404 contained expenses for non-utility software. The costs for Contestable Market software, Global Marketing database, and PacifiCorp Power Marketing (PPM) Non-Regulated development system are included in utility amortization expense. I recommend that these be excluded because they relate to non-utility operations. The impact is a reduction in revenue requirement of $562,000.

CORRECT CONSTRUCTION WRITE-OFF

Q. PLEASE EXPLAIN EXHIBIT NO. DPU 1.12.

A. PacifiCorp included adjustment 8.14.5 in its filing to remove a 1999 write-off of construction projects that had not been identified as to what account they should be transferred to in rate base. Subsequent to the write-off, the Accounting department determined where most of the facilities and equipment had been installed and the costs were charged to Plant in Service at the appropriate location. Projects not charged to plant in service were charged to Construction Work in Progress (CWIP), company tab 8.14.5 reflects this.

Subsequently, PacifiCorp determined that Adjustment 8.14.5 needed to be corrected because not all of the amounts charged to CWIP, and expensed to Account 930, Distribution Operation Supervision were removed. This distribution account was used because most of the projects were distribution related.

Exhibit No. DPU 1.12, corrects the error by reversing the amounts inadvertently charged to expense. The impact on revenue requirement is a reduction of approximately $1,427,000.

PROPERTY INSURANCE RESERVES

Q. PLEASE EXPLAIN EXHIBIT NO. DPU 1.13.

A. PacifiCorp made $100 million in accounting adjustments for the quarter ending December 1999. Several of these were removed through various adjustment in the test year filing. One of the adjustments PacifiCorp made was to increase property insurance reserves by $4 million.

Exhibit No. DPU 1.13 shows the balance in Account 228.1, Provision for Property Insurance, by month from September 1999 to December 2000. The $4 million jump can be seen in the November 1999 balance. A company memo dated January 13, 2000 explains the increase in property insurance reserves in these words

> Estimated annual expenses (for property insurance) have been between $5.0 million and $8.0 million per year. A positive impact on earnings will result if claims against the reserve are less than anticipated. With this reserve the potential of a negative earnings impact in the year 2000/2001 is mitigated[2].

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[2] PacifiCorp memo from Robert R. Dalley to CEC dated January 13, 2000. Proposed December 1999 Quarter-End Adjustments, page 2, CCS 13.25

Since annual expenses against the insurance reserve have been between $5-8 million per year, the $12 million reserve at the end of the test year appears to be too high. I recommend that the $4 million addition booked in November 1999 be removed from test year expenses. This reduces the test year revenue requirement by approximately $1,276,000.

ADD QUIPS PAYMENTS TO INTEREST TRUE-UP

Q. PLEASE EXPLAIN EXHIBIT NO. DPU 1.14.

A. QUIPS is a acronym for Quarterly Income Preferred Security. These are treated as equity by credit rating agencies, but because they are subordinated debt securities the interest is tax deductible. As of December 31, 2000, PacifiCorp had $352 million in QUIPS outstanding with an annual dividend requirement of $17.8 million. This amount is tax deductible for PacifiCorp. Therefore, this interest expense should be included in the Interest True-Up Adjustment 7.1. Exhibit No DPU 1.14 adds the Utah allocation of QUIPS interest expense to the Interest True-Up adjustment. This adjustment synchronizes the interest expense customers provide in capital structure with the interest expense used on the tax return. The impact is to reduce revenue requirement by approximately $4 million.

ADJUST UTAH DISTRIBUTION EXPENSE

Q. PLEASE EXPLAIN EXHIBIT NO. DPU 1.15.

A. This adjustment reduces Utah allocated distribution expense because of incorrect cost center coding. Some costs were assigned to Utah distribution when they should have been assigned to the system or to Wyoming. This adjustment corrects the mis-coding. The impact is to reduce revenue requirement by $7,744,000.

INTERSTATE ALLOCATION FACTORS

Q. PLEASE EXPLAIN WHAT ALLOCATION FACTORS WERE CHANGED IN THE MODEL.

A. There are three areas. The first is a correction to the Oregon temperature adjustment. In the month of October 1999 the figure 12 MW was entered instead of 102 MW. The impact is a slight reduction in the Utah demand factor. The Division made an adjustment to correct this input error, it is explained in the testimony of Rebecca Wilson.

The second removes Brigham City revenues and loads from the Utah jurisdiction to the FERC jurisdiction. The impact is a decrease in Utah revenues and demand and energy factors. The reasoning is explained in the testimony of Rebecca Wilson.

The final adjustment is to move an industrial contract customer's revenues and loads from the Wyoming jurisdiction to the system. This increased Utah's revenues, and demand and energy allocation factors. Mary Cleveland's testimony explains the reason and calculates the revenue change.

SAP SYSTEM AUDIT

Q. WHAT DID THE COMMISSION ORDER REGARDING THE SYSTEM APPLICATION AND PRODUCTS SOFTWARE (SAP) IN THE LAST RATE CASE?

A. In the test year used in Docket 99-035-10, the investment in the SAP software totaled $80 million. Since a beginning and ending average rate base was used the actual investment included in the test year was $40 million. The company and the Division supported adding the remaining half of the investment to the test year and removing the old legacy system. The CCS proposed removing all of the SAP software investment until the costs equal the benefits. The Commission adopted neither position and made no adjustment to the SAP investment, leaving the $40 million balance in rate base.

The Commission's order in Docket 99-035-10, dated May 24, 2000, states the following at pages 65 and 69-70

> What is important, however, is sustainable improvement in efficiency, measured over time as productivity gains, resulting in lower costs per customer and increases in the quality of service. An example of a useful measure, presented both in the current Docket and in just-completed ScottishPower merger approval Docket No. 98-2035-04, is non-production operation and maintenance expense per customer.
>
> On the other hand the evidence shows that the Company is transforming its internal processes through the implementation of SAP, and that some beneficial effect has been achieved during the test year.

> We wish to encourage the Company in these efforts and expect attention to operational efficiency as part of effective management. If successful, expenditures for re-engineering and training will produce future, recurring productivity gains.
>
> We adopt the recommendation … to require a performance audit of the entire project. One aspect of the audit should be to inform us of how an allocation of these expenditures should be performed. We await the receipt of the imminent semi-annual report on operations for 1999 and the ScottishPower merger transition plan before stating more clearly the audit requirements. Suffice it to say here, we expect such an audit to be limited, focused, and directly on the points raised herein by its proponents.

Q. WHAT DID THE DIVISION DO REGARDING THE SAP INVESTMENT FOR THIS RATE CASE?

A Mary Cleveland reviewed the SAP allocation between utility and non-utility operations. She discusses her recommendations in her testimony. I compared efficiency measures to determine if there were sustainable improvement in efficiency, measured over time as productivity gains.

Q HOW DID YOU REVIEW PACIFICORP'S INFORMATION TECHNOLOGY (IT) EXPENDITURES?

A. I reviewed a study of PacifiCorp's information system performed by an independent consultant in September 1999. I compared non-fuel operation and maintenance costs between years. I also discussed PacifiCorp's information technology and SAP system costs and benefits with the Oregon PUC staff and with several PacifiCorp IT employees.

I will first discuss the study done by Deloitte & Touche. This study analyzed both the processes and the costs of the IT function within PacifiCorp. It compared the processes with 23 other comparable organizations, and the costs with 26 other organizations. The process study showed that PacifiCorp has an effective and well-managed IT organization, with improvement opportunities in the areas of documentation, disaster recovery, and capacity planning.

The cost study showed that PacifiCorp has one of the lower IT expenditure rates per employee. PacifiCorp's expenditure per employee were $10,900, excluding the BSIP project, or $16,700 including the BSIP project. This compares favorably with the utility average of $18,900 per employee.

Q. PLEASE DISCUSS THE POSITION OF THE OREGON PUC REGARDING SAP.

A. Three members of the Division staff met for several hours with the members of the Oregon PUC staff. We sincerely appreciate their cooperation. Since their rate case is scheduled before the Utah case, their audit work was already completed, and they had stipulated with PacifiCorp on a number of issues. One of the areas we focused on was the SAP system.

The Oregon staff had disallowed 1/3 of the Customer Service System (CSS) in the prior case. In that case the staff determined that PacifiCorp costs for the CCS system were higher than other utilities. Since then the they have seen other utilities spend more than PacifiCorp on customer service systems. In the current case PacifiCorp's CCS costs appeared reasonable compared to other utilities, and the staff allowed all CSS costs, but recommended a disallowance of part of SAP costs. Ultimately, the staff and PacifiCorp stipulated on a SAP related disallowance of $800,000 in Oregon revenue requirement, and all of the CSS system costs were allowed.

After discussing SAP with the Oregon staff the Division staff feels that the reasons for the Oregon disallowance are not applicable to the Utah jurisdiction. The OPUC staff indicated the PacifiCorp installation of SAP was lower cost than other utilities, they found no indication of cost overruns, and the system is operating as planned. They stated that the disallowance was part of a stipulated agreement.

In considering the major IT investments, CSS and SAP systems, we determined that the Oregon position on IT costs compares favorably with the Utah Commission's position. The Oregon staff agreed to a disallowance of SAP totaling $800,000 in Oregon revenue, and no disallowance of CSS costs.

The Utah Commission has previously disallowed 1/3 of CSS costs, and the adjustment in this filing reduces Utah revenue requirement by $1.9 million. The Division is recommending no disallowance of SAP costs, with the exception of the non-utility portions discussed in Mary Cleveland's testimony.

Q. DID THE DIVISION MEASURE THE SAVINGS FROM SAP?

A. Measurement of savings would require calculation of the difference between current annual costs and what costs would be if the SAP system had not been in operation. It is not possible to identify how PacifiCorp would operate in the test year with out the SAP system.

The Division, like the Commission, felt that sustainable improvement in efficiency, measured over time as productivity gains, resulting in lower costs per customer were important. The Division measured non-fuel operation and maintenance costs per customer, non production operation and maintenance costs per customer and inventory per customer. The results are shown below.

Year	Non-Fuel O&M/cust.	Non-Production O&M/cust.	Inventory Per Customer
1997	$ 650	$ 494	$ 75
1998	$ 588	$ 445	$ 64
1999	$ 529	$ 378	$ 72
2000	$ 448	$ 300	$ 63

SAP installation was completed in June 1999. These cost per customer figures show a decline both in 1999, and in 2000. Reasonable tangible benefits of the SAP system include, savings from the 1998 employee reduction, avoided costs to support the Legacy system, improved cash management, streamlined human resource processes and payroll cycles, consolidated purchasing, fleet management, work management, and project scheduling. I know of no other company wide system deployed during this time period that would impact a broad range of operation and maintenance expenses. It is likely that the implementation of the SAP system is the cause of these savings.

Q WAS THE SAP PROJECT COMPLETED ON SCHEDULE AND WITHIN APPROVED BUDGETS?

A Yes. The SAP project terminated in June 1999. The original authorized investment in SAP was $141 million and subsequent changes increased the authorized budget to $167 million. The final cost was $164 million, so the project was actually $3 million under the authorized budget.

Q WAS THE SAP SYSTEM USED DURING THE TEST YEAR?

A Yes, it was installed and used in the normal business operations of the company during the test year. There are currently 3,347 regulated utility employees that are users of SAP.

Q IS THE SAP SYSTEM USED BY OTHER COMPANIES?

A Currently over 1,200 companies have purchased SAP. Over thirty utilities in the United States use SAP.

Q WHAT IS THE DIVISION'S RECOMMENDATION REGARDING SAP COSTS?

A. The Division sees measured improvements in efficiency over the two years that SAP has been in use. We believe that the SAP system was the probable cause of these savings, and recommend that SAP costs be included in the test year. Mary Cleveland will address the non-utility use of SAP.

WYODAK COAL CONTRACT

Q. WHAT WAS THE COMMISSION'S DETERMINATION REGARDING THE WYODAK COAL CONTRACT IN THE LAST CASE?

A. In Docket 99-035-10, the CCS witness Mr. Cardwell recommended an adjustment to bring Wyodak coal contract prices in line with market prices. The Commission did not adopt his adjustment, and stated:

> There has been no showing that this contract was entered into imprudently. Both the Company and the Committee agree that the current contract price exceeds market levels. Yet the Company claims it has tried to buy out this contract, but to date its efforts have proven unsuccessful. We will continue to review Company efforts in this regard. Given that the total costs of currently operating the Wyodak plant, including coal costs, are reasonable, we find no adjustment is necessary at this time3.

Q. WHAT IS THE CURRENT STATUS OF THE WYODAK CONTRACT?

A. Since May of last year, PacifiCorp has filed suit against Black Hills Corporation regarding the contract. As of mid May of this year, an agreement had been reached between PacifiCorp and Black Hills. The new contract is a series of new agreements that provide coal to Dave Johnston as well as Wyodak. Additional information concerning the contracts will be available later in this docket

Q. IS THE DIVISION RECOMMENDING AN ADJUSTMENT FOR WYODAK COAL COSTS IN THE CURRENT CASE?

A. No, the new contract agreement was signed outside of the test year. It would be inappropriate to include it in the current case.

<u>ACCOUNT 903 ALLOCATION FACTORS</u>

3 Utah PSC Docket No. 99-035-10, page 43 issued May 24, 2000.

Q. WHAT DID THE COMMISSION DECIDE REGARDING ACCOUNT 903 ALLOCATION FACTORS IN THE LAST CASE?

A. The Division witness recommended the Commission use the System Overhead (SO) factor to allocate FERC Account 903, Customer Receipts and Collections, instead of the Customer Number (CN) factor. The Commission order reads:

> Thus on this record, a basis for allocation other than number of customers is realistic. It follows that the Division's recommendation to use the general allocation factor, SO, pending further study is acceptable to us. ... We will expect the Division to work closely with the Company and other interested parties to resolve the technical points raised here so that an appropriate allocation factor may be adopted in the next general rate case.[4]

The Division compared the cost per customer, using the CN factor, for Accounts 901 through 910 (excluding 904 and 908) for each state. We found that Utah costs were $45.95 per customer, the lowest of any state. The total company cost was $48.31, and the next lowest was Oregon at $48.25 per customer. The CN factor gives Utah the lowest cost per customer of any state. Exhibit No. DPU 1.16 shows the calculations I have discussed

It does not appear to be reasonable to argue for some other factor when CN is used by all other states, and gives Utah the lowest cost per customer. The Division supports use of the CN factor for these accounts.

JIM BRIDGER ACCOUNTS RECEIVABLE

4 Utah PSC Docket 99-035-10, page 17, Issued May 24,2000.

Q. WHAT DID THE COMMISSION ORDER REGARDING JIM BRIDGER ACCOUNTS RECEIVABLE IN THE LAST CASE?

A. Jim Bridger is a company owned plant and mine in Wyoming. The investment in the mine is added to rate base as an adjustment in each filing because the investment is recorded on the books of Pacific Minerals Inc. (PMI), a subsidiary of PacifiCorp. In each prior filing the Jim Bridger accounts receivable from PacifiCorp were included in the adjustment that adds the mine to rate base. In the last Docket the CCS disagreed with accounts receivable portion. The Commission's order states:

> The Company claims that the accounts payable balance for Bridger Coal Company was included in the lead-lag study used to calculate cash working capital. The Bridger Coal receivable balance, in the Company's view, must be included in ratebase to offset the lower cash working capital that results from including Bridger's payable balance. The Division disagrees with the Committee adjustment, stating that if the accounts receivable balance is removed from ratebase it should be removed from the lead-lag study.
>
> The Company had ample opportunity to challenge the Committee's proposal and to provide evidence proving the Committee wrong. It did not do so. Furthermore, the cash working capital study is based on a lead-lag study that dates from December 1991. The record does not show how the current $7 million balance associated with Bridger coal sales is treated in the 1991 study being used in this Docket. In short, we have no basis upon which to reject the Committee's recommendation[5].

Q. WHY DID THE DIVISION OPPOSE THIS COMMITTEE ADJUSTMENT IN THE LAST CASE?

5 Utah PSC Docket 99-035-10, page 31, Dated May 24, 2000.

A. The Jim Bridger Coal accounts receivable balance is reflected in the lead-lag study, in both the 1991 study and the current 1998 study. If the accounts receivable balance is removed from Jim Bridger rate base it double counts the adjustment.

Q. ARE JIM BRIDGER ACCOUNTS RECEIVABLE INCLUDED IN THE CURRENT CASE?

A. Yes, it is included in Company adjustment 8.4.1 at $6.3 million, total company. The offsetting lead lag adjustment is shown in the 1998 lead lag study at page 4.1.1-1. The lead-lag study has not been entered as an exhibit in this docket. It has been available for the parties to review however. Customers get credit for the lag in payments to Bridger through the lead lag study calculation. Customers should not get credit again by removing the accounts receivable balance from rate base.

Q. WHAT EVIDENCE DO YOU HAVE THAT THE JIM BRIDGER ACCOUNTS RECEIVABLE IS INCLUDED IN THE 1998 LEAD LAG STUDY?

A. I have prepared Exhibit No. DPU 1.17 This exhibit consists of four pages from the 1998 PacifiCorp lead lag study. The first and second pages show the Utah expense and revenue lag calculations. The third page is a description of how the fuel lag is calculated, and states that the accounts payable from Jim Bridger coal is to be included. The final page is the calculation of fuel expense lag showing that Jim Bridger is included in the total.

SALE OF HYDRO UNITS

Q. WHAT IS THE DIVISION RECOMMENDING REGARDING THE SALE OF HYDRO UNITS?

A. On February 15, 2001, the Division staff met with Mr. Randy Landayls, PacifiCorp's Director of Hydro Resources regarding the sale of PacifiCorp's hydro units. There are about 1,100 MW in 53 hydro projects. If the smallest 25 hydro projects were sold, there would still be 1,000 MW of hydro resources. The ScottishPower transition plan called for selling the small hydro units because they were not efficient to operate, and were viewed as underperforming assets. However in light of increased power costs, the plans to sell these hydro units have been shelved.

Currently one hydro unit called the American Fork Plant, built in 1907 with a capacity of .95 MW, is up for license renewal. PacifiCorp's discussions with the Forest Service and Park Service to re-license the plant do not appear to be fruitful. The plant may be closed in the next year or two.

Because of their small size the sale of most hydro units would not normally require Commission approval or even prior notification. Commission rules only require approval for the sale of generating plants of 10 MW or greater. The Division believes that the hydro units are a state wide community asset. We believe it would be prudent for the Commission to be made aware of when hydro units in the state are first put up for sale. We recommend that the Commission require PacifiCorp to notify the Commission and Division when it decides to put a hydro unit in the state up for sale. The Commission and Division can then decide if any action from state regulators is appropriate.

Q DOES THAT CONCLUDE YOUR TESTIMONY?

A Yes.