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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of PacifiCorp for an Increase in its Rates and Charges	)	Docket No 01-035-01 **POST HEARING BRIEF OF THE DIVISION OF PUBLIC UTILITIES**

The following is the Memorandum of the Division of Public Utilities (DPU) addressing the remaining issues left in this proceeding after approval of the Stipulation. These issues are Net Power Costs, wholesale contract imputation and additional DSM investments.

I. INTRODUCTION

This case represents the largest increase in Net Power Costs ever requested by the Company and a corresponding large increase in net power costs proposed by the DPU. The large disparity in the two recommendations is attributable to three different areas: First, the Company for the first time is attempting to annualize short term firm and non-firm sales, raising the actual test year expenses for these two items by almost $200 million.[1] The DPU urges the Commission

[1] In general, net power costs will be presented on a total company basis. When a Utah specific net power costs figure is presented it will be noted in the Brief. Utah is approximately 38% of the total system.

to continue using actual firm and non-firm costs that occurred in the test year. Second, for the first time, ratepayers are being significantly harmed by the revenue credit treatment of long term wholesale transaction the Company has entered into. The DPU and others have argued that the Company is violating an earlier PSC Order that established how wholesale contracts were to be treated. The losses in the wholesale contracts which ratepayers are being asked to pay is directly attributable to the Company's risky strategy of relying on the short-term firm market to satisfy some of the requirements of their long-term wholesale contracts. The DPU and others are attempting to address this risk in such a manner that it will be shared by both the Company and customer. Third, the DPU is suggesting a variety of adjustments to the net power cost model that are intended to more accurately reflect the operations of the Pacifcorp system.

A second unique aspect of this proceeding is the Company's reliance on 2001 and some 2002 events to justify deviating from traditional rate-making practices. First, the Company is trying to convince the Commission to ignore precedent because some late 2001 and 2002 short term costs are above market prices, thus justifying building into rates higher net power costs than those incurred during the test year. Second, the Company points to its debt being placed on credit watch by Moody's and the confidential results presented by Ms. Clark. Both of these events should be given little weight by the Commission. Although these two events will be discussed in detail later, one overriding reason should be pointed out here: since the end of the test year, the failure of the Hunter plant and the bad water year in the northwest have increased net power costs by over $500 million. These events are classic looks outside of the test year in order to make a test year point and cannot be viewed in isolation. Many wholesale contracts expire in late 2000 and 2001. The Company has orders from most jurisdictions deferring Hunter costs. Finally, bad water years are normalized in rate cases.

II. THE DPU'S NET POWER COSTS ARE REASONABLE WHEN COMPARED WITH THE PAST AND WHAT PACIFCORP IS PROPOSING IN OTHER JURISDICTIONS.

Although the net power costs being presented in other jurisdictions, and what power costs have been in the past should not be dispositive, these should allow the PSC to have a level of confidence that the DPU's proposed final net power costs (NPC) are reasonable. Currently $415 million in NPC are build into rates (R. 1215). The Company is proposing an increase to $806 million. In Oregon for a 2001 test year the Company is proposing a NPC of $615 million.[2] Actual NPC for the test year are $620 million. The DPU, after making its adjustments to the Pacifcorp model and adjustments for wholesale contracts, proposes an increase of $120 million over what is currently in rates. The only actual estimate of a 2001 NPC presented by the Company was a February estimate of $760.[3] That estimate – any estimate of 2001 – includes the effect of Hunter and the bad water year. Since the end of the test year those two events alone increased NPC by $511. At least in Utah, Hunter costs will be recovered in a separate proceeding and bad water years are normalized out of NPC. Understanding the makeup of 2001 NPC, and recognizing that the market in the summer of 2001 is significantly lower than the market in 2000, the PSC should have some confidence that adopting a NPC suggested by the

[2]DPU 8.12SR.

[3]The Company now claims that their February estimate of $760 million is low for 2001. However, no new estimate was given except for some short term firm contract prices the Company had entered into above current market level.

DPU is both reasonable when compared with the past and when one looks at the very limited information we have on 2001 costs.

III. NET POWER COSTS SHOULD BE BASED ON ACTUAL SHORT TERM FIRM AND NON-FIRM COSTS AND NOT THE ANNUALIZED LEVELS PROPOSED BY THE COMPANY.

Probably the largest and least complex adjustment in this proceeding is the Company's proposal to annualize the high summer short term firm and non-firm prices for the entire test year. This raises costs from actual test year level by $149 million and Utah's revenue requirement by $55.3 million. The Commission should reject the Company's attempt to deviate from historical practices. This proposal violates the annualization rules of this Commission, and there is no way to determine if prices in the rate effective period will be at the levels suggested by the Company.

Short-term firm and non-firm prices have not been annualized in the net power cost model. In the last proceeding the Company for the first time used a market model to develop short term prices.[4] This attempt to use a market model was soundly rejected by the Commission in favor of actual test year prices. In that case the PSC stated that "the purpose of normalization in the context of a historical test year is to adjust actual information for known and measurable events occurring during the test year, establishing a normal and recurring level of costs and revenues."[5] In rejecting the use of market prices to establish historical levels the PSC stated that it is complex, risky, subjective and prone to error. Those reasons apply equally to this test year.

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[4]In this case, the Company used actual prices for the summer months, and market index prices for the summer to price all other months in the test year.

[5]Order in Docket No. 99-035-10 at p. 37.

The Company justifies its annualization of the test year data by stating it is following past PSC practices on annualizations.

The examples the Company gives as to PSC annualizations are contracts that either start or expire in the test year for long term power. When a contract expires during the test year, or a new one is started, the effect of those events are annualized for the entire test year. There is no valid comparison between a long term wholesale contract beginning or ending and a short term transaction. A new long term contract continues into the rate effective period. Its volumes are known. Its price are known. A short term firm or non-firm contract by definition expires in the test year. There are thousands of transactions ranging from hours up to a year. When one contract expires it may or may not be replaced. The needed volumes on a short term and non-firm basis vary dramatically from one year to another depending or weather and other factors. The prices one pays for non-firm and short-term firm transactions vary dramatically from one day to the next or even from hour to hour. It is not appropriate to rely on annualizations of long-term contracts as precedent for the annualizations of short-term non-firm and firm transactions.

In addition, the DPU does not believe that the annualization of short term firm and non-firm contracts meets the rules in R 746-407. In order to qualify for an annualization, the "change must be known to occur at a specific moment or moments in time."[6] Market prices vary constantly during the day or from one month to another.

The volumes purchased also vary dramatically from month to month and, more importantly, from one year to the next. The Company has left volumes unchanged even though when one applies higher prices, the volumes would not have been the same. For example, since

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[6]R746-407(3)(D).

prices went up, there have been numerous activities of the Company designed to reduce the need to buy the high priced short-term firm power. Here, another principle of R746-407 is not met: there must be little or no interdependence between price and volume. The standard annualization is where the price changes but the volumes remain the same. A postage increase or a wage increase can be applied to a set level of volumes. Finally, as can be seen from last summer's prices compared to this summer's prices, there is also no way one can claim that, "The change must be expected to be ongoing after final rates become effective."[7]

The best the Company can come up with is that it has entered into some contracts for this fall and next year that are at higher prices than the current market and are similar to last summer's prices. Therefore, the Company argues they have met the standard. An ongoing event after rates go into effect is best illustrated by the long term new contract example that the Company used to try to justify annualization of short term contracts. When that new contract is annualized in the test year, the price that will be ongoing during the rate effective period is known. The volumes during the rate effective period are known. Neither the price nor the volumes of short-term transactions are known and measurable as to what those prices and volumes will be during the rate effective period. Finally, the Division does not believe that using a market index to establish prices for the test year constitutes a known and measurable change. What the Company actually paid may be above or below the market. To hypothetically assume that all volumes were purchased at some market index certainly does not qualify as a known change.

[7]R746-407(3)(G).

A final reason given by Mr. Falkenberg is what he calls inclusion of hypothetical losses on long term firm transactions that are included in the Company's test year. This issue was essentially left unrebutted by the Company. The best way to explain this issue is to provide the explanation given by Mr. Falkenberg. He stated:

> Finally, and I think most importantly in the Company's rebuttal testimony, the Company never really did address the issue of the hypothetical losses. And I view this is an extremely serious problem in the Company filing. In my testimony, I have an example that I'd like to go over here that's related to the Cheyenne contract.
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> The Cheyenne contract terminated in December of 2000. The Company included in the test year an average price for this transaction of about 27.6 mils. The market price for power in the test year was 113.7 mils. Versus the actual price which I used of 43.5 mils.
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> When you look on a monthly basis the comparison of the market price with power the Company had to buy versus the actual price thta the Company was selling this transaction for, the Company lost about $20 million. It is not in my testimony to make an adjustment for that factor. There may be other witnesses that have addressed that; however, I don't address that.
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> The problem is, however, that the difference between selling at 27 mils and buying at 45 mils produces a $20 million loss, but under the Company's normalized or annualized market prices, the loss would be substantially greater. It would be $80 million. If this transaction wasn't in the test year, there would be an $8 million reduction to net power costs.
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> The problem is that this transaction has now ended. So the Company has built into its test year a cost of $80 million that never occurred in the first place and is not going to occur in the future either. It's over. This transaction is done.
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> And I think it would be inequitable and improper to include this kind of hypothetical loss into the test year. So that's the primary and I think the most significant basis for making this adjustment.

This is another example how the proposed annualization is not an ongoing event when rates become effective. Many contracts either have expired or are expiring in 2001. The Commission should not build into rates these hypothetical losses. In order to be consistent with the last rate case and to comply with R 746-407, the DPU urges the Commission to use actual non-firm and short-term firm costs incurred in the rate case.

IV. THE PSC SHOULD MAKE ADDITIONAL CHANGES IN THE NET POWER COSTS MODEL BASED ON THE TESTIMONY OF MR. FALKENBERG AND MR. HAYET.

A. The Commission should include in the model integrated system operations suggested by Mr. Hayet.

When the Company filed this rate case, it assumed that the two divisions were operating separately. In other words, it assumed that the merger never took place. PacifiCorp's reasons for not modeling an integrated system were lack of time, and a belief that any benefit from an integrated system was offset by other things left out of the model. The PD Mac model has included the benefits of an integrated transmission system ever since the merger. It was unreasonable for the Company to assume that the systems operate separately and exclude the benefit from an integrated system when they filed this case. The Division was put in the position in rebuttal of trying to make right something that should never have been left out.

Mr. Hayet in his direct testimony included in the model the effect of an integrated transmission system <u>as it had been modeled in PD Mac</u>. In rebuttal, the Company agreed that it had not modeled the transmission system but said when you do it correctly it is only worth $.8 million due in part to mistakes they found in the way the internal transmission system was modeled in the past.[8] The Company also placed limits on the external market transaction that can occur. These two changes, when applied to the DPU original adjustment, are the causes of the reduction in the adjustment to under $1 million. With the limited time available, since all of this was provided in rebuttal, Mr. Hayet accepted the "mistakes" the Company presented for internal transmission limits, but rejected the limitation the Company placed on external markets.

Two main reasons were presented for rejecting external limits provided by the Company: First, Mr. Hayet testified that the external limits were subjective and difficult to validate, particularly in light of other available data that showed different limits.[9] Second, the Company optimized and balanced the system in an uneconomic fashion. The market limits placed into the model by the Company satisfied market constraints but it did this based on an sub-optimal dispatch of the system. Mr. Hayet corrected for this sub-optimal dispatch.

With this correction there are four alternatives being presented for PSC consideration. First, there is the Company's $.8 million. Second, the benefits of Mr. Hayet's model, but including the internal limits corrected by the Company, results in a total Company adjustment of $16.8. Third, Mr. Hayet's optimal dispatch of the system, but including both the internal and external limits of the Company, results in an adjustment of $5.8 million. Finally, Mr Hayet discovered a transposition error when he originally filed his testimony that when corrected results

[8]These mistakes that the Company discovered were not provided to other states where a PD Mac model is being used.

[9]DPU 10.1 SR. This is a RAMP 6 map of transmission limits both internal and external that are different from what the Company is presenting in the power costs model.

in a proposed adjustment of $13.6 million.[10] With this correction, the DPU recommends that a $13.6 million total company transmission adjustment be made to the net power costs model. To limit the adjustment to only $.8 million seems to fly in the face of everything we believed about the Pacifcorp/Utah Power merger and is not consistent with the value of integration of the two systems.

B. 6 year average availability rates and planned maintenance outage hours.

The DPU/CCS recommend that the PSC adopt a six year outage rate instead of the 4 year rate currently being used. The six year outage rate more represents current conditions by smoothing out abnormalities.

The need for a longer data set can best be observed by reviewing DPU Ex. 9SR.5. This exhibit shows the effect on net power costs of using different availability rates. It shows that even small differences in availability rates can have large impacts on net power costs.[11] Three out of the four years picked by the Company, included in their average, produce significantly higher net power costs than either a ten-year average, the six-year average or 2000 data. All of these produce similar results in the model.

The Company's main response is to compare itself to other utilities to show that its availability rates are reasonable. Such comparisons have no relevance. Rates are not set based

[10]This adjustment includes the new Company internal transmission limits, excludes the Company's external limits and corrects the error discovered by Mr. Hayet.

[11]The Company argues that the differences between a 4 year and six year average are small and do not represent a trend. However these small differences should not be ignored since the impact on net power costs is so great.

on averages of other companies. The purpose of either a six year or four year average is to create in rates what best reflects current conditions.

Since each year's data reflects anomalies in that year's rate making, one looks at past averages in order to smooth out the blips from one year to another. Understanding that purpose, and looking at the ten years of data, which is similar to the six years, and the year 2000, should give the PSC comfort that a six-year average is more representative of normal conditions than the four years of data.

The Company argues that the four year average has always been used, and no one has challenged it in past rate cases, so therefore, any challenge today should be given little weight. In the past, whether one used a four, six or ten-year average made little difference since the effect on net power costs was minimal. Today with high market prices, the effect of even a small change is significant. The difference between a four and six-year average has almost a $100 million effect on net power costs and has a $16.9 million impact in Utah. Therefore, the Commission should give little weight to the fact that it has always used a four-year average and decide in this case which average best represents going forward conditions.

The Company also argues that by using a longer average there is double counting. The Company uses the years 1996, 1997, 1998 and 1999. Two additional years 1994 & 1995 are added by Mr. Falkenberg. The Company argues the double counting occurred because 1994 & 1995 were used in previous rate cases. Such an argument has no merit. Rate making is intended to represent the future and not the past and to create normal net power costs. Neither of those principals are violated by the use of either four years, six years, or ten years worth of data. The question is which most reflects normal and current conditions.

Finally, in evaluating this issue the PSC should look at what are reasonable results when compared with each alternative. The Company argues that there is no trend in availability rates. However the use of the four-year average produces nearly the highest impact on net power costs over any year individually or either the six or ten-year average. The best evidence to show the reasonableness of the six year average is that the six year average is very similar to both the ten year average and the 2000 data.[12] We strongly recommend that the six year availability rates be used.

C. The Cholla outage should be removed from the net power costs results.

In 1996 the Cholla unit had an outage that lasted 3000 hours. Even though it was a planned outage, when the technicians got into the unit, it required more work than the Company originally had planned.[13] In fact the Company indicated that it had never experienced a planned outage of this length. Two main reasons exist for removing Cholla.

First, the PSC has allowed deferred accounting for the Hunter unit which is an outage of similar length. The Company agrees that if deferred accounting treatment is given, that outage should be removed from net power costs. Since this is a similar outage in length, it should be similarly removed from net power costs since deferred accounting could have been requested for by the Company. It is not clear if Cholla would qualify for deferred treatment similar to Hunter.

The second reason is that unusual events should be removed from the calculation of net power costs because you would not want to build them into the results. Cholla is an event that

[12]DPU 9SR.5.

[13]Most overhauls last anywhere from four to eight weeks. R 486.

has never repeated itself and should be removed from the results. This adjustment has a value of $2.8 million total company and $1.1 million in Utah.

V. THE PSC SHOULD GIVE LITTLE WEIGHT TO EITHER THE TESTIMONY OF MS. CLARK OR THE COMPANY'S ABOVE MARKET CONTRACTS FOR THE SUMMER OF 2001.

Through the testimony of Ms. Clark, the Company paints a dismal financial picture for the period ending June 30, 2001. In addition, the Company advises the PSC that the lower market prices occurring this summer cannot help because the Company tied up some short term contracts at prices above current market levels. It is unclear how the Company wants the PSC to use this information. The Company will probably argue that the PSC should award them near their requested revenue requirement and not get bogged down in modeling disputes, since absent some significant relief, the Company may be downgraded and will not be able to cover this summer's contracts without additional rate relief.

The DPU believes that neither Ms. Clark's testimony nor the above market contracts should be given weight in deciding the issues in this proceeding. Both are clearly outside of the test year. In addition significant contradictory evidence has been presented that questions the value of this type of testimony. At most, these issues may raise the need for additional filings in 2001 based on actual 2001 Utah specific data. The information provided, however, is not probative on the test year adjustments being proposed.

Although the Company has provided some evidence that it has not been able to take advantage of lower market prices for the summer of 2001, such information is incomplete and of limited value. This type of incomplete data demonstrates why the PSC does not allow reliance on out-of-period adjustments to establish historical test year levels. First, this data is incomplete in that it only presents the prices of certain contracts but does not present the volumes needed to be purchased by the Company. Numerous long term wholesale contracts expired in late 2000 and during 2001, and the availability of Hunter led the Company to present a forecast in April 2001 in Oregon for significantly lower net power costs by the end of 2001.

Two events since the end of the test year need to be weighed in evaluating any probative value to either Ms. Clark's testimony on the Company's claim that 2001 power costs are higher than test year results. These two events are the Hunter plant and the bad water year. The combined effect of these two events on net power costs since the end of the test year is about $511 million. Even if net power costs are above test year levels, rate making has deferred the Hunter plant and would normalize the bad water year. On a rate making basis 2001 net power costs could be lower than actual net power for the test year or the recommendations of any of the parties.

Ms. Clark's ratios include both the effect of Hunter and the poor water year. When you remove the deferrals which include Hunter, the cash flow significantly improves.[14] The DPU does not believe it is reasonable to present these rations without adjusting the cash flows due to the probable recovery of these deferred costs. Division witness Judith Johnson also proposed to adjust Ms. Clark's exhibit to remove the adjustments for the Centralia sale included in the January hearings. If those adjustments had relevance in January, where one was looking at data

[14]The Company has orders allowing the deferral of a significant amount of net power costs. In other words the Company has the opportunity to recovery these costs. Auditors did not require the Company to write off these costs.

that included the sale, they have no relevance to the end of June 2001, where the yearly data does not cover the sale.

The commission should review Ex. DPU12.2 compared to 12.1, which shows that when valid adjustments are applied to Ms. Clark's ratios, the possibility of a downgrading is diminished.

In evaluating Ms. Clark's testimony the Commission should also ask itself what responsibility it has to address the issues raised by Ms. Clark. In this case, the rate of return was stipulated at 11%. That return produces sufficient interest coverage ratios to maintain an A bond rating.[15] This evidence means that with an 11% return the Company has the opportunity to have a sufficient interest coverage ratio to clearly maintain an A bond rating. Of course the Company will argue that it will not earn 11% because of regulatory lag, Hunter, a bad water year, lack of adequate relief in other jurisdictions and a variety of other reasons. But does that mean that Utah should abandon past rate making practices and award a rate increase based on factors partially outside of this state's control. If results in 2001 require additional rate relief, the Company should file for such relief. This case should not be used to solve any 2001 problems that are inadequately developed on this record.

In conclusion, the Division urges the PSC to give little weight to the testimony of Ms. Clark.

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[15]DPU Ex. 6.0 p. 21-22.

VI. THE DIVISION'S PROPOSAL ON WHOLESALE CONTRACTS IS A REASONABLE WAY OF SHARING THE SIGNIFICANT NEGATIVE REVENUE CREDIT IN THIS TEST YEAR CAUSED BY THE COMPANY'S STRATEGY IN THE WHOLESALE MARKET AND IS CONSISTENT WITH THE STANDARDS APPROVED IN THE 90-035-06 ORDER.

A. Introduction.

The Division through Ms. Wilson, the Committee through the testimony of Mr. Yankle and the industrials through the testimony of Dr. Anderson have all proposed adjustments to the Company's long term wholesale contracts. Although the amount of the adjustment from each party is different, their objectives are similar. Each party is addressing the significant negative revenue credit present in this test year. The negative revenue credit in this docket is traceable to the Company's strategy to rely on the short term market to satisfy their long term wholesale contract commitments.

Each party is proposing to adjust revenues from a number of long-term wholesale contracts that negatively affect retail customers. At least from the Division's perspective the central issue that must be decided is to what extent should retail customers be harmed by long-term wholesale contracts entered into by the Company and that are currently producing a significant negative impact on retail customers? Should this negative revenue credit be build into rates? We believe that such a result was never envisioned by the Commission. As early as the adoption of the standards in Docket No. 90-035-06, the Commission's goal was to protect customers from the possible harm that could occur by accepting the risks associated with including wholesale contracts in this jurisdiction.

The standards adopted in Docket No. 90-035-06 are in effect, but have not been complied with by the Company. The DPU adjustments are an attempt to apply those standards as the means established by the Commission to protect customers.

B. The avoided costs standard used to review wholesale contracts adopted in the last rate case did not eliminate the standards adopted by the Commission in Docket No. 90-035-06.

In Docket No. 99-035-10, the PSC adopted the use of the DPU's avoided costs calculation as a measure for a revenue imputation for certain wholesale contracts. In addition the PSC determined that the DPU's calculation of transmission losses was reasonable. Pacifcorp in this Docket claims that the Commission has in a fully litigated case established a standard for imputations of wholesale contracts and it should not be reheard in this docket. The Company proposed an adjustment in its initial filing imputing revenues based on its interpretation of the last Order. The DPU, obviously, does not agree that the PSC decided the imputation issue in the last rate case. In fact, in light of the Order in Docket No. 90-035-06, the Company in its filing in this rate case is violating that Order by not proposing an adjustment based on that earlier Order.

First, the Order in the last case is not dispositive of what is to happen in this case because the Commission explicitly limited the use of that Order to the 1999 rate case. The PSC stated that the use of avoided costs is reasonable for "purposes of revenue imputation in this docket."[16] That fact alone puts the imputation issue squarely before the Commission in this case. If the Commission meant to answer for once and for all what to do with all of these long term wholesale contracts, then why did it establish a task force to address the wholesale contract

[16]Order in Docket No. 99-035-10 at p. 50.

issue?[17] In addition, the issues presented in the two dockets are different. In the last docket a positive revenue credit existed. In this Docket a significant negative revenue credit exists. Ratepayers are being harmed by these wholesale contracts. This case must determine how that harm will be shared between the Company and customers. The last case was to establish a reasonable revenue credit that benefits rate payers, not a means of dividing up the harm as in this case.

Another significant reason the avoided costs standard is not binding in this docket is that the parties became aware of an earlier Order of the Commission that was not known at the time of the last rate case.[18] An Order of the Commission cannot be abandoned by the Company's failure to comply with that earlier Order and the passage of time. In the last rate case the Commission recognized that policy cannot be changed outside of a fully advised Commission. With respect to the WAPA issue the Commission stated:

> By incorporating transmission system benefits into jurisdictional revenue requirement, Utah Power argues the Commission has altered the imputation policy.
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> We reject the argument that a Commission regulatory policy can be changed in this indirect way. First, the Company is obligated, if it seeks to change existing regulatory policy, to bring to our attention any new considerations it believes may warrant the change. This is

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[17] It was in a task force meeting that the Order in Docket No. 90-035-06 was brought to the attention of the parties. Thus, Pacifcorp was aware of the 1990 Order when it filed this rate case. It could and should have addressed that Order in its original filing.

[18] Ms. Wilson indicated that if she had been aware of that 1990 Order she would not have proposed the avoided cost standard.

> to be done in an open, public proceeding, where the sworn, cross-examined testimony and evidence, not just of the Company but of all parties, forms an evidentiary record. See, Salt Lake Citizens Congress v. Mountain States Telephone and Telegraph, et. al, 846 P.2d 1245 (Utah 1992).[19]

The *Charitable Case* is directly relevant to this case. In 1990, in order to address risks for customers caused by the adoption of normalized power costs and a revenue credit treatment for wholesale contracts, an Order was entered that set forth a standard to gauge the reasonableness of long term wholesale contract. That rule was adopted with the approval of the DPU, CCS and Pacifcorp. It became binding on Pacifcorp in the same fashion that the Commission's exclusion of charitable contributions from rates became binding on Mountain Bell. The Charitable Case clearly holds that rules adopted by the Commission that were intended to have future applicability cannot be changed by the Company's failure to comply. To argue that the last rate case established a rule on wholesale imputation that is binding in this case when the Commission was not aware that it had adopted in 1990 a way to protect customers from the risks associated with wholesale contracts ignores the main principals established by the Court in the Charitable Case. The Company must be open, not engage in gamesmanship, and the Commission must be fully advised of all relevant facts. Policy can only be changed if the Commission understands it is changing a policy. That clearly is the not the case of the avoided costs standard adopted in the last case.

[19] 99-035-10 p. 24-25.

C. The standard adopted in the 90-035-06 order was specifically designed to protect ratepayers from possible harm from wholesale contracts being given revenue credit treatment.

In Docket No. 90-035-06 the Company requested that the EBA be eliminated, that power costs be determined using a normalized net power cost model (PD Mac) and that a revenue credit treatment be established for long-term wholesale contracts. With the acquisition of the Cholla, Craig and Hayden plants, the Company had opportunities for new wholesale transactions. Under FERC rules, wholesale contracts were becoming more market based. Under those requirements new wholesale contracts were "limited to the average costs of a pool of resources made up of the Company's most expensive thermal generation."[20] It is for these types of contacts that revenue credit treatment was requested rather than placing them in a FERC jurisdiction. The advantage to the company was that below embedded costs contracts in the early years could be covered by state revenue requirements in anticipation of those contracts being above embedded costs in the later years.

The parties' response to the Company's request was to recommend suspension of the EBA, use of normalized net power costs and allowing revenue credit treatment for long-term wholesale contracts with certain conditions. These conditions were presented to the Commission by Ken Powell and were intended to address the risk to retail customers of accepting revenue credit treatment for long term wholesale contracts. The conditions were agreed to by the

[20]May 1990 testimony of George Duvall p. 32 quoted in CCS Ex. 7 p.11. Mr. Duvall stated that this new FERC pooled pricing "ultimately produces a price substantially greater than a price based on average embedded system cost and therefore provides greater benefit to retail customers."

Company and incorporated into the Commission's December 7, 1990 Order in Docket No. 90-035-06.[21]

Three contracts were apparently submitted for revenue credit treatment and addressed by Mr. Powell in testimony filed in November 1991. The Company's filing tried to demonstrate that the contracts cover marginal costs, make a contribution to fixed costs and after a period of time cover full embedded costs.[22] When Mr. Powell filed testimony addressing these contracts, he recommended revenue credit treatment be given but also proposed a modification of standard 4D.[23] A task force was created which submitted a report to the Commission in April 1993.[24] Even though the PSC never adopted this report or otherwise altered its December 1990 Order, all parties who participated in the report recommended that criterion 4D be changed to read:

> Pricing shall be structured such that over the life of the contract retail revenue requirement will be protected from increases resulting from resource acquisitions needed to serve the wholesale contract.

All parties recommended that contracts be evaluated using the criteria established by the task force and the December 1990 Order. The Division understands that many years have passed since these standards were adopted. Nevertheless, we recommend that they be applied as much as possible in this proceeding. Ms. Wilson testified that she believes the standards adopted in the

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[21]The Commission's Order refers to testimony of Ken Powell on pp 11-13. That testimony is in this record as Cross Ex. 4.

[22]See Cross Ex. 5. Other than the three contracts in this exhibit, no similar filing for any wholesale contract has ever made.

[23]There is no record of the Commission acting to approve these three contracts.

[24]Cross Ex. 6 is the task force report submitted to the PSC recommending a change in criterion 4D.

early 1990's more adequately protects retail customers from harm caused by wholesale contracts than the avoided cost standard used in the last rate case.

Up until 1995 wholesale sales were a relatively flat portion of the company sales and appear to have been mainly served out of excess generation. The pooled resource concept continued to be used until the mid 1990s when it was abandoned by the Company.[25] The value of the pooled resource method was described in some detail in the Company's 1993 overview of wholesale transactions. That report stated:

> The resource pool pricing method is advantageous to retail customers because of the insulation it provides for retail prices from new higher cost resources. Wholesale customers absorb the bulk of costs of adding new resources, as a result of the roll-in feature, and <u>the lower cost resources are reserved for retail customers</u>. Retail customers are also insulated from resource cost uncertainties. Once resource acquisitions have been prejudged to be prudent, if the new resources are more expensive than originally forecast, the prudently incurred additional costs can be recovered through wholesale sales. If new resources cost less than the existing pool resources, the new resources would not be rolled into the wholesale sales pools and would be reserved for service to our retail customers. (Emphasis added)[26]

D. After 1995 wholesale sales increased dramatically and the Company began to rely on the market to satisfy those contracts rather than excess generation thus exposing customers to enormous market risk. If the Company had continued with the pooled resource method, we may not be facing the large increases being proposed here.

A significant amount of evidence was presented to show the dramatic change in the Company's wholesale activities. This increase occurred not only in the west, but also included the Company's expansion into other markets in the U.S. and elsewhere. The evidence also

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[25]Cross Ex. 8 shows that wholesale sales were flat until the 1995 time period.

[26]See CCS Ex. 7 p. 15. 1.

demonstrates that the Company abandoned the pooled resource method of pricing wholesale contracts and instead relied on the market for establishing wholesale prices. Finally, the Company decided for a variety of reasons to rely on the short term market to serve some of the requirements of these wholesale contracts. This reliance on the market, coupled with the huge amount of wholesale contracts, exposed ratepayers to enormous risk. Its is those risks that the imputation adjustments are intended to address.

A review of Cross Ex. 8 demonstrates this dramatic increase in wholesale activities. After 1995 wholesale sales increased dramatically so that by 1997 there were more wholesale sales than retail sales. By 1997 total wholesale sales exceeded generation. Along with the increases in sales, wholesale purchases increased dramatically during the same time period. It is the contracts entered into in the mid 1990's that are the main focus of imputation. Although Ex. 13.1 does not have data back to 1990, it shows on a resource availability basis for the summer coincident peak the dramatic increase in short term transactions designed to cover the shortfall created by these wholesale contracts. It is that shortfall that is at least in part the cause of this rate increase. It is that shortfall that the imputations are intended to address.

Numerous documents were presented by the parties to demonstrate the planned increase in wholesale activities by the Company and how it intended to serve these new long term wholesale contracts. Probably one of the clearest examples of this new strategy is found in RAMP 4:

> In the past, wholesale sales were a minor part of PacifiCorp's total revenues. The Company used the revenues to help offset retail prices. However, several changes are occurring: 1) wholesale is becoming a larger part of the Company's total business, 2) wholesale prices are

> declining and 3) that part of the business carries increasing risks and potential rewards.
>
> The wholesale part of the business is growing rapidly and the company is looking at wholesale sales as a major business activity. Wholesale marketing will increasingly evolve as a separate business with its own strategies, rewards and risks.
>
> The greater the Company's activity in the wholesale market, the greater the potential rewards and the greater the risks. Those who bear the risks should also benefit from the rewards. The Company would prefer to not expose retail customers to the higher risk/reward situation. Equity capital is a better place for such activities. The Company will experience upward pressure on retail rates if it cannot maintain the current level of wholesale contribution. Changing conditions in the wholesale markets mean the Company must take on greater risk to achieve the same level of wholesale contributions. However, the Company continues, for now, to use the retail credit approach for wholesale sales. These are transition times and that approach may change in the future as other changes occur, some expected and some unforeseen. These changes could include alternative regulation, deregulation, an restructuring. (Emphasis in Yankel's testimony)[27]

RAMP 5 explained how the Company would serve these new wholesale contracts. In addition, RAMP 5 made certain other assumption changes that may have had an impact on the lack of adequate firm resources to serve load today. First, in RAMP 5 the Company indicated that it would satisfy the imbalances in its load and resource plan by increasingly relying on the wholesale market to meet commitments of long-term wholesale contracts. The Company assumed that for a 5 year planning horizon, which includes the test year, that it would increase the amount of short-term wholesale purchases made to achieve a balance between wholesale purchases and sales.[28] A second major assumption change in RAMP 5 that affects this test year

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[27]CCS Ex. 7 p 18.

[28]See DPU Ex. 8.0 p. 14, quoting from RAMP 5.

was an assumed 10% reduction in load and a decision that it would not be reasonable to "plan for and build resources which it expects to lose within the next five years."[29] This loss of load never materialized. The Commission should recall that it did not acknowledge RAMP 5 and that RAMP 6 was not produced as required until this year. The Commission rejected RAMP 5 for reasons that are relevant to this proceeding. One of these reasons was that the Company did insufficient risk analysis on their course of action.

The market exposure or imbalance in load and resources that was to be covered by short term firm purchases was not a "slight" mismatch but amounted to over 2000 mw. in 1997 and 1998 and over 1500 mw in the year 2000.[30] Even the loss of Centralia cannot account for the large amount of short term purchases required this year. Most short term purchases occur during the summer period. During the test year the high market prices occurred during the same period. It is no wonder that the Company is requesting such a large rate increase. We believe retail customers should not be responsible for the entire increase when a large part of the increase was caused by the Company's wholesale activities. The proposed imputation is designed to address this.

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[29]See. DPU Ex. 8.0 p. 16, quoting RAMP 5.

[30]DPU Ex. 13.1.

E. The DPU proposed imputation using embedded costs is reasonable and is consistent with the 1990 Order.

The imputation proposed by the DPU for wholesale contracts is an attempt to apply the criteria established in the 1990 order. Contracts that are more than half way through their term and do not cover embedded generation and transmission costs were adjusted. Ms. Wilson asserted that applying this standard to these contracts is consistent with the Docket No. 90-035-06- and the recommendations of the 1993 task force report.

The embedded cost standard was applied rather than marginal cost because in this case marginal cost is above embedded cost and the adjustment would be greater. It allows for a reasonable sharing of the increase in net power costs.[31]

The number of contracts affected by Ms. Wilson's adjustment varies depending on the embedded costs determined reasonable by the Commission and the net power costs found reasonable. At the stipulated revenue requirement, with the DPU use of actual short term firm and non-firm power, 13 contracts are affected and the total Utah decrease in net power costs is $23 million.[32]

The Company will probably argue that we have not actually followed the 1990 Order since the remedy for non approval is a FERC jurisdiction. Ms. Wilson testified that using

[31]DPU Ex. 8 p. 19.

[32]DPU Ex. 8R p. 4-5 see Ex. 8.2 revised which provides results with varying assumptions. If the Commission continues to use the avoided cost standard from the last case, the DPU does not believe that Pacifcorp correctly calculated the adjustment. In order to comply with the Order, an additional adjustment to the Company's revised imputation must be made. The avoided cost number should include a secondary sales credit. This adjustment would raise the imputation to $3.6 million total company.

embedded costs is similar to "putting underperforming contracts into a separate jurisdiction,"[33] and in any case, there is no FERC jurisdiction. The Company has not filed contracts for revenue credit treatment. To argue that these contracts must be placed in a FERC jurisdiction ignores the reality of the last decade in which the 1990 order was ignored.

At the last moment of the hearings, the Company submitted information that this proposed adjustment is worse than placing the contracts in a FERC jurisdiction. The Company claimed that this information was filed at the last minute to respond to Ms. Wilson's description of a FERC jurisdiction, which differed from the Company's. The purpose of the imputation is to protect customers from harmful wholesale contracts. The Company should not be able to shift the harm back to customers by claiming we are not meeting the 1990 order when in fact it was the Company's obligation to file contracts for approval and file rate cases in conformance with the standards adopted in the early 1990's.

F. The benefits from revenue credits the Company claims have flowed to retail customers should be given little weight.

Mr. Waters produced an analysis showing huge benefits for customers from the revenue credit treatment of wholesale contracts over the years. There are two problems with Mr. Waters' analysis. First, the Commission in the last rate case indicated that it would not guage the prudence of wholesale contracts by looking at all of them together, but would look at each individual contract to determine if an imputation should be made. Second, Mr. Waters acknowledged that his calculation compares what was included in rates to an imprudent practice

[33] DPU Ex. 8 p. 19.

of making no long term sales, but instead selling all surplus at short term rates.[34] The record shows that other options could have been studied that would have yielded more realistic results.

The DPU evaluated the benefits of the revenue credit method over the years. DPU Exhibits 8.14 and 8.15 SR, which look at the revenue credit over the years from two different perspectives, show that the revenue credit benefitted both customers and the Company over the years, but that in the year 2000 the net loss rose to $200 million with a net total loss of $216 million. These losses are calculated with no discount rate and without taking into account load growth. They are conservative. These losses show the need for imputation even when one looks at the entire life of the revenue credit mechanism.

G. The sale of the Centralia plant should have little or no effect on the DPU's proposed imputation.

The Company estimated that on a Utah basis, the impact of selling this plant on net power costs was about $75 million. The DPU believes the impact of the sale is significantly less when it is evaluated against actual short term purchases, rather than annualized results.

The DPU does not believe that the Commission, in allocating the gain 95%-5%, meant to address how cost recover, of losses caused by the sale of the plant would be dealt with. In other words, each proceeding must look at the supply mix the Company has chosen to serve its load, it must look at prudence, and it must address how and when costs are to be recovered (the annualization issue).

One must recall that the plant was sold in May. The power only needed to be acquired from May to the end of the test year. However, for rate making, the sale of the plant was

[34] R 290-292.

assumed to have occurred for the entire test year. The annualized higher net power costs were applied to months where actual purchases were not required to be made. Therefore, the estimated $75 million impact to Utah is overstated. The DPU's proposed increase in net power costs may even cover the replacement power costs.

Finally, replacement power for this plant was acquired with the Company's portfolio. Thus, the replacement costs must be evaluated against the utility's heavy reliance on the short-term market.

H. SMUD Adjustment.

The Company proposes an imputation for this contract based on the $ MWH found in the last rate case, where the Commission adopted the renegotiated SCE rate as the basis for imputation for the SMUD contract. The SCE rate was originally entered into around the same time as the original SMUD contract. The Commission used the new SCE rate, which was actually lower than the original SCE rate, because the new SCE rate more reflects current market conditions. If the Commission wants to continue to use current market conditions, then obviously the new SCE rate more accurately reflects what occurred in the year 2000. One must remember that this is a very long term, below market priced contract, in which the Company received $94 million up front. That money went to shareholders. This history is the reason why different treatment on this contract is propped than the imputation suggested by Ms. Wilson.

The Company's main response is that the adjustment is becoming so large that the $94 million benefit is being lost. No attempt was made to show the actual value of the $94 million, nor is there any way in this case for customers to recovery that benefit. The imputation is the only mechanism available to protect ratepayers from this below cost contract.

VII. THE DSM ISSUES

Upon taking the stand during the revenue requirement hearings, Jeff Burks modified page 3 line 14 of his Direct Testimony to delete the request that "the Company's revenue requirements going forward be adjusted to include" $35 million for the first year of the Energy Office's DSM initiatives. As corrected, the testimony now reads: "We propose $35 million to fund the first year of a multi-year DSM initiative as set out by UEO's expert witness." (R. 515-517) Mr. Burks goes on to request that the Company "file a design for a DSM cost recovery tariff that would be equitable to all customer classes." (R. 518) When asked to explain why Mr. Burks made this correction, he stated: "I think there was some confusion that the Energy Office was . . . proposing an increase in revenue requirements in this case of $35 million." Although it is not totally clear what Mr. Burks intended by his correction, it appears that the UEO withdrew its request that Pacificorp's revenue requirement include $35 million for its DSM initiatives. The UEO having withdrawn that request, and there being no other party advocating that the $35 million be added to the Company's revenue requirement, one might reasonably conclude there is nothing remaining for the Commission to decide on this issue.

Yet, it is apparent that the UEO wishes to have its initiatives funded by some means other than inclusion in revenue requirement. Mr. Burks testified that the $13.5 million which is currently under consideration by the Commission for recovery under a deferred accounting order (Docket No. 01-035-21, Application filed 27 June 2001) is included in his $35 million proposal. (R. 551). Thus, the UEO appears to be requesting that the Company collect $21.5 million by some means other than revenue requirement to fund the remainder of its programs.

The Division suspects, though the record is not clear on this point, that the reason the UEO made the change in its testimony was a concern with its proposal being a single-item rate case, a prohibition which the UEO was not aware of at the time it filed its testimony. The UEO's proposal for collecting the $21.5 million is a tariff rider, which Dr. Nichols describes at page 7 of his Direct Spread/Cost-of-Service testimony filed on 15 June 2001:

> Q. Assuming a DSM rider and your proposed schedule of DSM investment, what DSM charge would be established in this case?
>
> A. The residential rider would be established at a level of 3.58 mills per kWh, based on year 1 residential DSM costs and test year sales of 4,933,857,000 kWh. <u>The rider would be adjusted annually to include any utility under-recovery or over-recovery in the next year's rider.</u> If the utility spends exactly the amounts I set forth in my previous testimony, and there were no crediting of any purchased power market savings and no sales growth, <u>the rider would be at the following annual levels in years 2-6 (mills/kWh): 2.37, 1.66, 1.82, 1.99, and, in the last year, 2.17.</u>

(Emphasis added). Two things are apparent from this testimony: (1) there would be annual retroactive adjustments for under- or over-recovery; and (2) the amount to be collected would decrease some years and increase others, without consideration of other changes in the Company's revenue requirement at that time. The method for funding the UEO initiatives would thus appear to constitute a single-item rate case which the Utah Supreme Court prohibited in the *Wage Case* (*Utah Dep't of Business Regulation v. PSC*, 614 P.2d 1242 [1980]).[35] The Division presumes, but is not certain, that this is the reason the UEO made the change in Mr. Burks' testimony when he took the stand.

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[35] Unlike the HELP program, which included a defined amount to be collected annually from revenue requirement, and not trued-up between rate cases for under- or over-recovery.

At least two questions are left unanswered: (1) By what mechanism does the UEO intend to fund the $21.5 million? (2) If it is not to be funded by a revenue requirement increase, is a rate case the proper venue in which to request some other funding mechanism? It is difficult to give a meaningful answer to these questions based on the record now before the Commission. One reason the Division favors funding DSM through deferred accounting orders is that it appears to be a legal means of funding such initiatives.

It is conceivable the UEO may be thinking of collecting the $21.5 million through the pass-through statute, 54-7-12(3)(d)(i), which reads:

> When a public utility files a proposed rate increase based upon an increased cost to the utility for fuel or energy purchased or obtained from independent contractors, other independent suppliers, or any supplier whose prices are regulated by a governmental agency, the commission shall issue a tentative order with respect to the proposed increase within ten days after the proposal is filed, unless it issues a final order with respect to the rate increase within 20 days after the proposal is filed.

Even if one were to somehow conceptualize DSM as "an increased cost to the utility for fuel or energy purchased," (which seems on its face to be somewhat of a stretch), and thus avoid a single-item rate case, the tariff rider proposed by the UEO, which calls for truing-up of over- and under-recovery, would presumably be prohibited by the *EBA Case* (*Utah Dep't of Business Regulation v. PSC,* 720 P.2d 420 [Utah 1986]). In footnote 4 of that opinion, the Utah Supreme Court stated:

> The PSC attempts to find statutory support for the EBA by arguing that it was instituted in an attempt to implement the fuel cost pass-through legislation. It is hard to understand how this advances the PSC's case here. But, in any event, that suggestion seems farfetched. There is nothing in the pass-through legislation that sanctions the establishment of an EBA. The pass-through legislation's purpose is quite limited: it permits utilities to cover excessive fuel costs which could not be otherwise accurately forecast by allowing those

> costs to be immediately passed through to consumers via abbreviated proceedings. U.C.A. 1953, § 54-7-12(3)(d). The EBA, on the other hand, takes into account revenue items as well—something well outside the purposes of the pass-through legislation. The only relation that we can discern between the pass-through legislation and the EBA is that in between general rate-making proceedings the PSC uses pass-through proceedings to adjust the fuel cost component of the EBA. We find no authorization for the establishment of EBA's in the pass-through legislation; rather, we assume that the EBA order was promulgated under the Commission's ample general power to fix rates and establish accounting procedures. U.C.A. § 54-7-1.

It thus appears that the UEO's initiatives, even if they were somehow conceptualized as increased fuel costs, could not be funded by means of the pass-through statute because the tariff rider adjusts the rate for under- or over-collections.

It has never been clear exactly what the Court meant when it said "we assume the EBA order was promulgated under the Commission's ample general power to fix rates and establish accounting procedures." What can be said is that if the Commission were to either attempt to create an EBA, or authorize a tariff rider, under its "ample general power to fix rates," it would still have to comply with the *Wage Case* and could not violate the rule against retroactive rate making. One might reasonably conclude that a tariff rider which adjusts annually for over- and under-collection appears, on its face, to violate the rule against retroactive rate making. In two relatively recent cases, the Utah Supreme Court has carved out two exceptions to the rule against retroactive rate making. In *MCI Telecommunications v. PSC*, 840 P.2d 765 (Utah 1992), the Court recognized an "exception for unforeseeable and extraordinary increases or decreases in expenses." (at 772). In the *Charitable Case* (*Salt Lake Citizens Congress v. Mountain States Tel. & Telegraph Co., 846 P.2d 1245 [1992]*), the Court held that the rule does not apply where there is utility misconduct. These are the only two judicially-sanctioned exceptions. There may be others out there, but there is no obvious reason for concluding that DSM should be an exception. If one believes that "justice and equity" somehow require that DSM constitutes an exception, where and how does one draw the line?[36] Since the Commission's power to "establish accounting procedures" appears to be a legal vehicle for managing DSM, attempting to forge a new exception to the rule against retroactive rate making seems both unnecessary and unwise.

Finally, if Mr. Burks' testimony on cross-examination is to be taken at face value, the Commission have no decision to make on this issue. Mr. Dodge and Mr. Burks had the following exchange:

> Mr. Burks: I don't believe I asked the Commission to order the Company. I thought our testimony reads, we recommended the Company do the following.
> Mr. Dodge: Okay. What are you asking the Commission to do, then?
> Mr. Burks: To act—expedite on the basis of the Company's proposed DSM implementation plan that we ask them to file.
> Mr. Dodge: If the Company chooses not to accept your recommendation and file within 30 days the program design, etcetera, on the 14 programs that Dr. Nichols recommends, you're not recommending this Commission order that? It's just you hope they will, and if they do, you hope the Commission will act expeditiously?
> Mr. Burks: It would appear so.

(R. 591-92) From the foregoing, it seems the Commission has nothing to decide, either in the revenue requirement phase of the case, or the spread portion of the case, on the DSM issue.

Although some of the above comments may seem more appropriate in a brief on rate design than revenue requirement, the confusion on the UEO's position, together with the legal

[36] In *Stewart v. PSC*, 885P.2d 759 (Utah 1994), the Court held that the rule against retroactive rate making is not constitutionally-based: "We hold that the rule against retroactive rate making is not constitutionally mandated. Rather, that rule is based on sound rate-making policies, not constitutional in nature, and is subject to a number of limitations and exceptions." (at 777) The Court indicated that "justice and equity may require appropriate adjustments in future rates to offset extraordinary financial consequences." (at 778)

difficulties surrounding the proposed tariff rider, either of which could be dispositive of the revenue requirement issue, required the Division to respond at some length. The Division will also be filing rebuttal testimony on this issue in the cost of service/rate design phase of the case.

Dated this 21st day of August 2001.

____
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____
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