POST-HEARING MEMORANDUM

In the matter of

PACIFICORP 2001 GENERAL RATE CASE

Docket No. 01-035-01

Introduction

The present PacifiCorp General Rate Case before this Commission is of more than usual import. PacifiCorp is using revenue credit treatment and power cost modeling to pass on to ratepayers the large losses the Company has sustained in recent wholesale power trading activities. The revenue credit method and power cost modeling were adopted in Utah over a decade ago under circumstances very different from those which exist in this proceeding.

The revenue credit method was adopted to benefit ratepayers with the revenues from the sale of surplus generation power without exposing them unduly to the risks inherent in the wholesale power market. Power cost modeling, for ratemaking purposes, was adopted to estimate the revenues associated with surplus generation and the generation costs to serve both wholesale and retail load. Procedures were developed to normalize data assumptions in order to place the ratepayer at risk for normal system operating conditions and to relieve him or her of the risk, for instance, of fuel costs above forecast levels or bad hydro conditions. This allows the utility to receive the benefits--as well as to take on the risks--of actual net power costs being lower or higher than expected.[1].

Fitting the Company's recent wholesale trading practices into revenue credit treatment and accurately modeling its high volume, highly complex wholesale power trading activities in order to determine normal and recurring costs and revenues for the future rate period, is more akin to beaching a whale than intelligent rate making. The Company's wholesale trading activities today are wholly different in kind and number from what was before this Commission a decade ago when revenue credit treatment and power cost modeling were first proposed by the Company.

This sea change in the Company's wholesale power business in the last ten years, and the Company's effort to now transfer the risks of that activity to ratepayers by means of the net power cost increases it is requesting in this proceeding will necessarily require the

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[1] In fact, it was the Company's request to use this method, as shown in the Direct Testimony of Verl R.Topham, witness for Utah Power and Light in 90-035-06 when the Company requested an end to the Energy Balancing Account:

Q. The EBA is a mechanism which places the risk of fluctuating power costs on the customer. If the EBA were terminated, this risk of fluctuating power costs would be placed on the Company. Why is the Company willing to accept this risk?

A. The Company is willing to accept this risk because we believe the risk is manageable. The Company believes it is placing the risk of management practices on those what make the business decisions–management–not customers.(Direct Testimony of Verl R. Topham, Docket No. 90-035-06, page 13).

Commission to re-think and re-structure the extent to which the risks and rewards that arise out of a regulated power company's participation in a volatile wholesale power trading market are to be shared between shareholders and ratepayers.

PacifiCorp's original filing in this matter also raised numerous revenue requirement issues which were addressed by the Division of Public Utilities, the Committee of Consumer Services and Intervenors in discussions and negotiations with the Company prior to hearing. These revenue requirement issues were resolved by the parties in a July 12, 2001 Stipulation subsequently approved by the Commission. Because of that Stipulation, this Post-Hearing Memorandum of the Committee of Consumer Services will confine itself to the very important net power cost issues raised in this General Rate Case.

Argument

1. THE COMMISSION'S 90-035-06 ORDER SUSPENDING THE ENERGY BALANCING ACCOUNT AND ADOPTING THE REVENUE CREDIT METHODOLOGY IS THE NECESSARY STARTING POINT FOR CONSIDERING HOW THE COMPANY'S POWER TRADING LOSSES SHOULD BE TREATED IN THIS PROCEEDING.

A. Despite Factual Differences Between the Company's Wholesale Power Activities in this Proceeding and the 1990 Case, the Commission's Reasoning in the 1990 Case Regarding Management Responsibility and Rate Payer Risk Are Relevant to this Proceeding.

Revenue credit treatment and power cost modeling–so much the focus of the present proceeding-- were born out of the 1990 Utah Power and Light General Rate Case where this Commission, at the Company's urging, suspended the energy balancing account ("EBA"), adopted the Company's proposed modeling of power costs, and approved the Division of Public Utilities' criteria for revenue credit approval of certain wholesale power contracts (Phase I, Docket 90-035-06 Order, pages 8 and 16-17).

The Commission in the 1990 case was considering treatment of a relatively few long-term firm and wheeling wholesale sales transactions to dispose of Company surplus power. The level of the Company's present wholesale power market activity--where electricity is traded as a commodity in large volumes involving complex hourly and daily transactions-- had yet to emerge when that case was heard and ordered. And, ten years ago the Company had not yet targeted the wholesale power commodity market as a new major sector of its business, characterized in its 1994 Annual Report as "marketing, brokering and trading", where "The company will sell both electricity commodities and services, and will aggressively pursue new markets." (PacifiCorp 1994 Annual Report, page 3).

A critical element before the Commission in the 1990 case was the question of risk; specifically, the risk to ratepayers in revenue credit treatment and how it might be mitigated. The factual circumstances before the Commission were relatively simple. The Company had surplus power that could be generated and sold on the wholesale market by means of a few long-term firm contracts at prices which would generate revenues that would more that offset the cost to generate the power and therefore would benefit the ratepayers. The question was how to do this without exposing the ratepayers to open-ended risk of wholesale losses. The Commission-approved answer provided that all revenue credit contracts meet at least minimal earnings levels and be approved by the Commission.

With the exception of three contracts, this approval procedure was never initiated by the Company after the 1990 case, and none of the contractual transactions given revenue credit treatment by the Company in the present proceeding were ever so reviewed and approved–nor could they have been. It would be difficult to find a better way to illustrate the enormous difference between wholesale power trading today and 1990 than to imagine the logistical impossibility of the Commission reviewing and approving the long-term contracts that were initiated in the second half of the 1990s which were to be supplied, not out of the Company ‘s own excess capacity, but from short-term firm power purchases which the Company’s present power trading activities engender.

Because of these marked differences, one must be very careful in trying to fit the present case and its very different circumstances into the 1990 case testimony and order. However, revenue credit treatment and power cost modeling are with us today because of the 1990 case, and because the revenue credit treatment sought by the Company in this case imposes upon ratepayers not only much of the open-ended risk associated with its wholesale power trading business but large, already-realized losses as well. Given what is at stake for ratepayers in the Company’s net power request, it is altogether appropriate to review other critical features of revenue credit treatment as fashioned in the 1990 case. Those other critical features were (a) the extent of management responsibility and (b) the limit to ratepayer risk.

<u>Limit to Ratepayer Risk.</u>

In suspending the EBA, which had "served the public interest well" in protecting ratepayers from “the untoward results of persistently misforecasted fuel costs and off-system purchases and sales”(Phase I, Docket No. 90-035-06 Order, pages 5- 6), and adopting the revenue credit method, the Commission also adopted certain approval procedures which a contract must comply with to be given revenue credit treatment. The express purpose of those approval procedures was to mitigate ratepayer risk. This is plainly set forth in Division witness testimony cited in the Commission’s order. That testimony states, in part, as follows:

> “The rates in the new contracts that Pacificorp has signed with Sierra, Puget and Nevada Power all return less than fully embedded costs in the near term. . .Later those rates rise above embedded costs so that over the long term (present valued) the contracts return the same or more revenue credits to firm rate payers as tariffed rates do. At least that is the way they are supposed to work. . . I am concerned that we have no guarantee that they will work that way. Difficulties in our economy may make the forecasts inaccurate, or the forecast may simply be wrong.” (Written Testimony of William B. Powell, Phase I, Docket No. 90-035-06, pages 9-10).

And:

> “If we treat these contracts as revenue credits, then Utah ratepayers could be penalized by less than embedded cost revenues in the near term with not enough offsetting greater revenues in the long term. . .
>
> . . . we have three other concerns that I label the ‘such a deal’ problem, the ‘betting other people’s money’ problem and the ‘it ain’t my business’ problem. . .
>
> As long as the utility has a surplus of power, contracts such as these are supplied with no increase in fixed costs. . .
>
> When the surplus disappears, then each sale below full embedded cost creates a clear cross-time subsidy, where current ratepayers subsidize the rates of future ratepayers. . . At this time we do not have an accurate forecast of the duration of the present surplus.
>
> Should there be some limit to how many of these sales can be made? . .
>
> If we treat these contracts as revenue credits, then effectively the ratepayers guarantee the shareholders against any loss on these contracts. . .

> . . To what degree should ratepayers be involved in something about which they know little? . . .”

To address these risk concerns, Division witness testimony proposed the following procedure:

> We assume that the ratepayers are willing to assume some risk, but not all, if that risk has a reasonable potential for lower rates and doesn’t involve excessive risk of loss. We therefore recommend the following with regard to these three contracts:
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> 1. The wholesale sale contracts in this case that are approved by the Commission be treated as revenue credits.
>
> 2. If the cumulative contract revenues for each customer in some future year falls more than 10% below that forecast in this case as shown in UP&L 11.1 Tab 26 the revenues will be imputed in such case at a level half way between actual and forecast. This allows the shareholders to share in the risk of gain.
>
> 3. If the cumulative contract revenues for a customer in some future year exceeds the forecast in this case, by more than 10% as shown in UP&L 11.1 Tab 26 the revenues will be imputed in such case at a level half way between actual and forecast. This allows the shareholders to share in the risk of gain.
>
> 4. No additional discounted wholesale contracts should be given revenue credit treatment **<u>unless</u>** the utility can show to the Commission’s satisfaction that the sale can be made without additional investment in fixed cost until such time as the contract revenues at least match tariffed rates.
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> 5. All the above recommendations 1.4 are a package recommendation.” (Written Testimony of William B. Powell, Phase I Docket No 90-035-06, pages 11-14).

In response to a question:”Are you recommending this as a permanent standard that any future wholesale sale also meet?”, witness Powell stated: “No, this is a new approach that will need some review over time, especially when any new wholesale contract is proposed.” (Powell Written Testimony, Phase I, Docket 90-035-06, page 14).

It is abundantly clear from the testimony and factual context of the 1990 case that revenue credit was never adopted in Utah as a mechanism for treating all Company wholesale trading transactions. Only those particular contracts were to be accorded revenue credit which satisfied certain minimal revenue levels and were approved by the Commission. Moreover, if such approved contracts subsequently failed to perform as projected, revenue could be imputed to them in order to mitigate ratepayer risk.

Management Responsibility

At the risk of giving Company attorneys in this proceeding further cause to complain that testimony by Company representatives in the 1990 rate case is being quoted and used out of context, it should nevertheless be evident to a reasonable reader that some statements by Company management in that case on management responsibility and accountability were made and have import for the very reason that they have merit and value beyond the factual context in which they were offered. They address generally-recognized standards of responsibility and accountability, and are phrased as such. Among such statements is that of Company witness Topham that "The Company believes in placing the risk of management practices on those that make the business decisions - management - not customers". (Prefiled Direct Testimony of Verl R. Topham, Docket No. 90-035-06, page 13). This statement of Mr Topham carries weight not because it has specific applicability but because it is a well-recognized principle of business management.

It is true that Company witness Topham never stated in the 1990 proceeding that Company management takes responsibility for the Company's large-scale wholesale power trading activities. He couldn't have, because those activities and the wholesale power commodity market the Company participates in today were not yet in existence in 1990. This, however, in no way neutralizes or undermines Mr. Topham's general statement on Company management responsibility. The risk of Company management practices should indeed fall on those who make the business decisions–management not customers, and this is so whether one is considering abolition of the EBA or the treatment of the Company's present wholesale power trading business.

A. <u>Recent Company Wholesale Power Trading Losses Are a Direct Result of Company Business Activities for which Company's Management and its Shareholders Bear Responsibility</u>

The Company has recently sustained very significant losses as a result of sudden and very large price spikes in western wholesale power trading markets where the Company buys and sells power on a month-by-month, day-by-day, and hour-by-hour basis. It may be true, as Company witness Watters testifies, that these transactions were undertaken to match Company resources with sales commitments–both retail and wholesale. However, it is also true that such transactions have little to do with the limited revenue credit purpose discussed in the 1990 case of benefitting ratepayers with revenues from the sale of surplus generation. In fact when Mr. Watters speaks of "balancing and optimizing" the system, matching resources against commitments, he is speaking of a total resource consisting of not just Company generated power, but generated power *plus* purchased power being matched against retail requirements and wholesale commitments which it actively sought (see Watters' Testimony, Reporter's Transcript of Proceedings, July 30, pages187-189, and July 31, 2001, pages 333-334). By the middle

1990s, the Company's firm wholesale trading activities had moved far beyond anything that could be described as merely selling surplus generated power. As Committee witness Yankel states in his written testimony, after having reviewed the Company's trading activities:

> "To meet its increased wholesale obligations, PacifiCorp relied on all available resources. Although electrons are not color-coded, these firm wholesale sales were incremental to the sales (retail and wholesale) that existed at the time. Therefore, additional supply had to be procured. What is notable is that the Company relied on supplies in the wholesale market, rather than acquiring or building new generation plant, to service these new, firm wholesale obligations. Thus, there was a significant increase in purchase power (firm and non-firm) that coincides with this increase in firm wholesale sales. (Yankel Prefiled Direct Testimony, page 20).

The Company's own statements during this time best explain how the Company's means and ends of wholesale power trading had fundamentally changed. Consider, for example, the Company's pronouncement in its November 1995 RAMPP-4 Report that:

> "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. . . 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." (PacifiCorp RAMPP-4 Report, pages 12-13.

Given the major changes in the Company's focus on wholesale trading activities by 1995, the quantum growth in its trading activities, the newly-complex and different sale and purchase transactions then being entered into, and the fundamentally different way in which Company management viewed such activities, how is it now inappropriate or contrary to precedent for this Commission to consider the Company management's present wholesale power trading activities the same way the Company has for years: not as a "minor part" of the Company's revenues and business engaged in for the limited purpose of offsetting retail prices, but rather as a major Company management activity undertaken to serve management's particular business strategies and risk and reward calculations. The Company's wholesale trading activities, which produced considerable losses during the test period have everything to do with those business strategies and risk/reward calculations and little, if anything, to do with the sale of surplus generated power to benefit ratepayers. It is now only fair that this Commission place the consequences of Company management's wholesale trading activities where management has for so long advocated that it belongs: upon the those who make the business decisions–management–not customers.

Assuming that this Commission would still desire to maintain revenue credit treatment in some manner, there is nothing in the 1990 Order or in subsequent Orders of the Commission that would prevent the Commission in this proceeding from limiting the exposure of ratepayers to the risks associated with the Company's long-term firm wholesale trading risks and losses. Such a limitation could be accomplished in a manner consistent with the 1990 order and previously utilized by this Commission in subsequent orders treating net power cost issues: the Commission can impute revenues as mentioned by Division witness Powell in the 1990 case, as it did in the last rate case, and as proposed by Division and Committee witnesses in the present proceeding.

C. Sale of Centralia Did not Cause the Company's Wholesale Power Trading Losses and this Commission's Approval of that Sale Did not Absolve Company Management of its Responsibiltiy to Foresee the Consequences of that Sale including the Need for Replacement Power.

Company witness Watters cites (1) the sale of the Centralia generating plant in May 2000, (2) the Hunter Unit #1 outage, (3) the second worst water year on record in the Pacific Northwest, and (4) retail load growth, as primary causes for the increase in the Company 's short-term purchases during the summer and fall period of year 2000 when the spikes in power costs occurred. (Watters' Written Rebuttal, pages 14-15). However, as Mr. Watters correctly points out, the bad water year and the Hunter outage occurred outside the October 1999 through September 2000 test period.

Discussion at the Hearing tended to focus, perhaps unduly, on the Centralia sale because it occurred during the test period and because Company witnesses appeared to argue that the Commission's approval of the Company's sale of Centralia somehow thereafter absolves Company management of any responsibility for Centralia's replacement power costs. This position can be questioned for many reasons. For example, Company representatives in the hearing on the proposed sale acknowledge the continuing authority of the Commission to review and fairly adjust future Company rates–including any aspect of such rates impacted by Centralia power replacement costs. (See page 5 of Commission Order, Docket No. 99-2035-03) Further, language in the Commission's Centralia order assessing future risks of the sale must necessarily be read in its proper context; namely who (as between shareholders and ratepayers) is to be compensated from the proceeds of sale for the risk of replacement power costs, and in that context the Commission concluded that the ratepayers were more at risk. Finally, it requires a strained reading of the Commission's Order indeed to conclude that it says that if replacement power costs were markedly higher because of management error or lack of prudence, or because a management business sector which for years had formulated its own business strategies and made the resulting daily and hourly trading decisions suffers substantial losses, that the Centralia sale somehow shields management and its shareholders from those consequences.

Further, it is important to remember the context in which revenue credit treatment arose. The Company was acquiring surplus generating capacity, and it was the sale of energy from that surplus generating capacity, until it was needed for retail service, which was supposed to provide added revenues to offset power costs to ratepayers' benefit. It was Company management's responsibility to manage that surplus power. And it was Company management who recommended to the Commission that Centralia be sold, and provided an analysis which factored in the cost of replacement power and showed a revenue requirement decrease to ratepayers if the Centralia plant were sold. (Commission order, Docket No. 99-2035-03, page 2). If Company managment's business decisions were wrong, i.e., it should have known that the sale of Centralia exposed the Company to wholesale power market trading risk because there was insufficient surplus generating power to fall back on, or that it failed to timely hedge against that market risk or should have known it could not hedge the risk and therefore should not have proceeded with the Centralia sale, how would such circumstances translate into a conclusion that the Commission's order somehow transferred the consequences of those management decisions to the ratepayers?

Company argument that the Centralia sale somehow justifies the transfer of its wholesale power market trading losses to ratepayers is distortion of the purpose and end which revenue credit treatment and power cost modeling were to serve.

2. PACIFICORP'S POWER COST MODEL BUILDS INTO FUTURE RATES UNPRECEDENTED POWER COST SPIKES WHICH OCCURRED IN THE FINAL FOUR MONTHS OF THE TEST YEAR, AND INCLUDES FAULTY DATA WHICH DERIVE NORMALIZED NET POWER COSTS THAT ARE UNREPRESENTATIVE OF WHAT POWER COSTS WILL ACTUALLY BE DURING THE RATE EFFECTIVE PERIOD.

A. The Objective of Normalizing Power Costs During a Historical Test Year is to thereby Derive Costs Representative of what Actual Power Costs are Expected to be during the Effective Rate Period.

What value is even the best model of future costs and revenues if the imputs are either incorrect or computed in such a way that the results are unreliable? In its last rate case, Docket 99-035-10, where the Company's modeling of net power costs was also a major issue, the Commission stated:

> "The purpose of normalization in the context of an 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." (Report and Order, Docket 99-035-10, page 36).

When the Company in the 1990 case proposed replacement of the EBA by calculating net power costs on a normalized basis, Company witness Duvall defined "normalization" as:

> ". . . the process of modifying the actual test year data by removing all known abnormalities and making adjustments for all known changes. Normalization is done so that the test year is representative of the conditions that are expected to exist." (Prefiled Direct Testimony of Gregory N. Duvall, Docket No. 90-035-06, page 13).

Thus, the only real measure of the usefulness or accuracy of the Company's net power cost modeling in the present case is the extent to which its reflects what the normal recurring level of costs and revenues will be in the effective rate period.

B. **<u>The Company's Normalized Power Cost Model Has Produced Power Prices Unrepresentative of what Prices Are Expected to be in the Effective Rate Period</u>.**

The Company's requested $391 million increase in net power costs over what is now in rates may reflect the dramatic increase in wholesale power prices in the western region during a few months of the test year, and may allow the Company to recoup its past power trading losses. These, however, are not the objectives of power cost modeling.

The Company does attempt to validate its modeling results by reference to the dramatic increases in power costs in the western region in recent months. Thus, the testimony of the Company's Chief Executive Officer, Judi Johansen:

> "There is nothing that isolates this utility or the state of Utah from the impact of the volatile western wholesale market and there is no reason why rate outcomes here should be different than elsewhere." (Rebuttal Testimony of Judi A. Johansen, Docket No. 90-35-10, page 4).

This bandwagon logic ignores very sound historical and factual reasons why power costs and resulting rates in Utah should be different from what perhaps has occurred with other utilities in other parts of the western region. First, the Company enjoys a surplus in generated power over what is needed to serve retail ratepayers. Even if the Company, by means of long-term firm wholesale contracts, has sold that surplus and more besides in recent years, several of those long-term sales will have terminated before or early into the rate effective period, placing the Company again in a *surplus* and not a *deficit* position with regards to generated power. Thus, higher power prices in the new rate period should translate into lower net power costs for rate payers because of revenue credit treatment.   Second, power costs are already lower in the western region than they were in the test year, and may go even lower.

In contrast to the bandwagon logic of the Company is the much more germane comment of UIEC expert witness Chalfant regarding Company witness CFO Karen Clark's testimony that recent high power prices have been harmful to the Company:

> There's no doubt they have been harmful. The question is, did they need to be that harmful or is it because PacifiCorp is selling power and buying power way beyond its requirements."(Testimony of Alan Chalfant, Reporter's Transcript of Proceedings, August 2, 2001, 9:00 a.m., page 1006)

However, neither high power prices in the western region nor Company trading losses are the key issue here. The key issue is whether the Company's recommended net power cost computation reliably represents what those costs will be in the effective rate period? And there the answer is "no".

The record provides compelling evidence of the Company's errors, faulty assumptions, and annualization and normalization mis-steps in its power cost modeling that have inflated its net power costs in this rate proceeding.

<u>Production Model Errors</u>

Several clear errors have been identified in the Company's power cost model. Some have been acknowledged by the Company, but others have not. The Company has acknowledged its error in its Colstrip 3 and 4 capacity ratings, the failure to model its system on an integrated basis, and load and spinning reserve corrections. The Company also pointed out errors in its modeling such as the need to treat the San Diego contract as a long-term firm sale, which increased net power costs. And to its credit, the Company also discovered a few other errors which it made all parties aware of that reduced net power costs. These acknowledged errors reduced the Company's net power cost filing of $812.6 million by approximately $6 million. However, there are also other errors not yet acknowledged by the Company, such as Committee and Division witness Hayet's discovery of a $5.8 million error in the manner in which the Company balanced its east and west network without attempting to minimize power costs. (Surrebuttal Testimony of Philip Hayet, pages 6-8)

Faultly Assumptions

The Company has made several faulty assumptions in its power cost model. Some are discussed under other headings below. Two critically important ones are highlighted here.

1. The Company's model builds in an incorrect assumption that the Company will continue to experience a deficit in power supply in the future rate period when in fact its power supply is expected to change from a deficit to a surplus. Committee and Division witness Falkenberg highlights this incorrect assumption on page 14 of his Prefiled Direct Testimony, and quantifies the very significant dollar impact on normalized power costs. The Company has several power sales contracts now priced well below the normalized market prices the Company assumes in its net power cost model and which will terminate by 2001 year end. Witness Falkenberg further points out that excluding these contracts and their 633 MW of average demand

from the model reduces net power costs in the test year by $413 million. Even more significant is his observation that because these contracts will terminate prior to the new rate period and because that effective new rate period is expected to see a surplus and not a deficit in Company power supply:

> “This means that the *higher* wholesale prices rise, the *lower* PacifiCorp’s net power costs will fall because the Company will be able to sell its surplus into the power-starved Western grid. Thus the Company has depicted a situation of big net power costs by selectively applying a mix of historical and projected data that is representative of neither the past nor the future. Just the opposite from the result of the Company’s faulty power deficit projection.(Randall J. Falkenberg Direct Testimony, page 10).

For reasons to be discussed shortly, Committee and Division witness Falkenberg proposes to remedy this problem by using actual market prices.

2. The Company model faultily assumes that the wholesale power market prices the Company incurs in the future will remain at or near the prices experienced near the end of the test year and annualized in its model, when in fact there is already wholesale market evidence that those prices could be significantly lower. First, there is in the record clear evidence that wholesale power market prices are already lower than those annualized by the Company as a result of a cooler summer on the west coast, greater than anticipated customer efficiencies, and the price cap on electricity imposed by the June 19, 2001 FERC Order. (See July 30, 2001 hearing testimony of Company witness Watters, pages 226, 227 and 228). Second, as UIEC witness Chalfant correctly points out, the Company’s model assumes the large price increases annualized in its model reflect the transactions the Company *would actually make*, whereas

“. . . to assume that the Company would have made the identical transactions regardless of price. . . is economic nonsense. When prices increase four-fold or more from a prior year, players in the market will respond.” (Prefiled Direct Testimony of Alan Chalfant, page 3).

Annualization and Normalization Mis-Steps

The Company's power cost model in this proceeding does a much better job reflecting the unprecedented cost of power spikes which occurred at the end of the test year than it does representing what the Company's power costs are going to be during the effective rate period. The Company would like to have it believed that there is a direct and validating relationship between the high cost of power in the western region at the end of the test year and the high net power costs its model calculates for the future rate effective period . However, as demonstrated above, there are several very compelling reasons to show just the opposite. It is, thus, of critical importance to ensure that the power costs the Company derives from its model truly represent what *the Company* with its own Company-specific requirements -- not those of utilities generally in the western region, or some artificial, average company mechanically buying and selling power at some average industry index price-- will likely encounter during the rate effective period.

Many of the reasons why the Company's normalized prices are unrepresentative of what its power costs will be during the new rate period have to do with the mis-steps the Company has made in annualizing and normalizing costs and prices in the test year. Correcting these mis-steps results in very sizeable reductions in the Company's net power cost request in this proceeding. We highlight the following mis-steps here:

A. The Company annualized monthly average market index prices rather than actual contract prices it paid or received. Because these index prices are mathematical averages they may in fact differ dramatically from prices the Company actually paid during the test year or would actually pay during the rate period. The Company's actual price, depending upon time of day, time of year, might be much higher or lower that the statistical average index price. UIEC witness Chalfant in this regard states:

> "These adjustments that are based on monthly and seasonal average prices are applied to prices that change hourly. More specifically, from the information we have been provided, it does not appear that these adjustments make any attempt to use the timing of the Company's purchases and sales to develop properly weighted average monthly prices." Direct Testimony of Alan Chalfant, page 3).

Committee and Division witness Falkenberg further states:

> ". . . the Company's new normalization method is highly speculative, incomplete and inconsistent. To develop these normalized prices the Company does not even use prices it actually paid. Rather, it uses a published index of on-and off-peak prices from the Dow Jones service. In the end, it is not an index of actual prices paid by PacifiCorp, or anyone else. Rather it is a survey reflecting average prices of certain transactions voluntarily provided by certain market participants."(Direct Testimony of Randal Falkenberg, page 18).

To this criticism Company witness Widmer responds that the Company's modeling is:

> "consistent with historical ratemaking treatment the Company has received in the state of Utah". (Widmer Rebuttal, page 6)

With regard to witness Falkenberg's criticism of the Company's use of the Dow Jones Price Index, Widmer responds:

> "The calculations of the indexes may not include all the transactions that occurred in the market. However, the calculations are representative of all transactions, and are not based on selected transactions or transactions of a limited number of participants." (Rebuttal, page 10); and "Market prices have been transparent to all participants since the market opened up several years ago. Certainly not every transaction the Company carries out is at the index price, but the index shows the general condition of the market and the Company trades in that market and can not dictate more advantageous prices without losing transactions to other parties." (Rebuttal, pages 9-10).

Mr. Widmer's above defense of Company modeling may pass in a time of stable market prices where any error caused by using index pricing instead of actual Company transaction prices would likely have been small. However, where large and volatile price changes are occurring--not only daily but hourly--which would not only affect the timing of a reasonable and prudent customer's purchases and sales but also makes possible wide differences between any average market price and what the Company's actual strike price was or would be at any moment--the shortcomings of market average index prices in such circumstances should be painfully evident to even a casual observer.

In response to Committee and Division witness Falkenberg's criticism that the Company's normalization of prices is not consistent with the precedent the Commission set in the last rate proceeding and "is the antithesis of a known and measurable change" (Falkenberg Direct Testimony, page 19), Company witness Widmer attempts to shift the focus to "annualization", as follows:

> "The method that the Company used to annualize known increases in market prices may not be perfect. However, given the information available to the Company, the method captures the logic of annualizing known and measurable changes, and captures reasonably well the magnitude of the changes. (Rebuttal, page 12).

The best way to address this response of Mr. Widmer is to refer to the Commission's rule governing the annualization of test-year data, Rule R746-407-3, which states, in part:

> "An item or test year data may be annualized in the determination of a utility's rates if it meets the following criteria:
>
> A. Annualization of price-level changes will normally be allowed.
>
> B. Annualization of volume-level changes with minimal interdependent investment/revenue/cost relationships will normally be allowed.
>
> C. Annualization of volume-level changes with significant interdependent investment/revenue/cost relationships will be considered on a case-by-case basis, and annualization of such changes will not constitute precedent.

D. The change must be know to occur at a specific moment or moments in time.

E. The effects of the change must be measurable.

F. The change must occur on or before the effective date of a final Commission order setting rates.

G. The change must be expected to be ongoing after final rates become effective."

Just when did the Company's cost for a short-term purchase of power change on an ongoing basis into higher cost that would continue through the rate effective period? What was that price? Was it the same price the Company paid four hours later, or the next day, or the day before? What relationship does that price have to the price index published by Dow Jones? How can it be verified? How do we know that the Company in the new rate period would make the same purchase at the same time under the same price conditions? The uncertainties and improbabilities multiply, because what the Company attempts to annualize is neither known or measurable or ongoing after final rates become effective.

B. Where the Company normalized changes in price it did not develop normalized sales volumes consistent with those normalized price levels, which produces an incomplete and skewed result. (Falkenberg Direct Testimony, page 22).

> "To annualize price changes of a contract, only the prices are changed, although the energy amount may be different. Messers. Falkenberg and Chalfant do not seem to think prices impact volumes when they propose their adjustments for so-called losses on short-term purchases and sales." (Widmer Rebuttal, pages 10-11).

C. Even though indices for both firm and non-firm transactions are available, the Company used the same underlying Dow Jones index to compute prices for short-term firm transactions and secondary sales, thus ignoring the difference in the value of these products and the Commission's reasoning in Docket No. 99-035-10 that market prices should be different for firm and non-firm products. This same defect in the Company's normalized prices in Docket 99-035-10 was one of the reasons the Commission rejected the Company's normalized prices in that proceeding. (Falkenberg Direct Testimony, page 24). In response to this criticism Company witness Widmer states:

> ". . . a review of market prices for the last year shows that firm prices are generally higher than non-firm, but not always. . . The claimed relationship between firm and non-firm is far from certain. In addition, the volumes of the short–term firm transactions are significantly higher than non-firm transaction volumes. As a result, the firm indexes are statistically more significant." (Widmer Rebuttal, page 10).

What is Mr. Widmer trying to say here? He apparently concurs that firm prices generally have greater value than non-firm. What if firm indexes are "statistically more significant"? Does that mean they don't affirm the value difference between firm and non-firm transactions? Does it mean that non-firm indexes are even less reliable than firm indexes in reflecting what the Company's actual non-firm sale and purchase prices might have been? If the Company here is seeking to accurately normalize these transactions for rate making purposes, during a period of often very high prices where even slight price differences–when annualized or normalized for the entire test year--can have very large dollar consequences, is there any justifiable reason for not reflecting the value differences between non-firm and firm transactions–or at least specifically indicating where an exception to that general rule applies?

D. The Company's normalized model includes several long term firm contracts that expired by or in December 2000 and whose prices in most instances are well below the assumed market prices used in its model, with hypothetical losses on those contract sales for rate making purposes that are far in excess of the actual losses during the test year and in excess of any losses that will occur when the new rates are in effect. (Falkenberg Direct Testimony, page 28). To illustrate this point witness Falkenberg states:

> "As an example, consider the Cheyenne sale. This transaction had a price of $27/mWh and was scheduled to end in December 2000. Based on actual market prices, the Company lost approximately $22 million during the test year on this transaction. While this was unfortunate, it is not nearly so bad as the outcome in the normalized modeling produced by the Company. Under the PacifiCorp normalized market prices, the loss on Cheyenne is over $80 million in the test year. Considering that the sale was supposed to end three months after the end of the test year, it seems highly inequitable to build permanently into rates $60 million in excess of the actual "loss" on the transaction."
> (Direct Testimony, pages 28-29).

Because of the inter-dependency of the various adjustments proposed by witness Falkenberg's he clarifies how this modeling effort might be addressed by the commission:

> "If the Commission adopts the Company's market price normalization method, I submit it *must* eliminate from the test year the hypothetical losses on sales terminating on or before December 2000. These transactions have now all ceased. As an alternative adjustment, I propose that the test year revenue shortfall for these terminating transactions be amortized over five years. This would reduce net power costs by an additional $82.4 million on a total Company basis compared to my primary recommendation of using actual market prices and eliminating the losses on short-ter firm transactions. If the Commission decided against its standing precedent requiring use of actual short-term firm and secondary prices, this adjustment would be an equitable alternative to use in place of the strict historical test-year convention. Note again that this alternative is applicable to only the Committee's case." (Direct Testimony, pages29-30).

Company witnesses never really responded to Mr. Falkenberg's criticism. Once again, this illustrates that when non-Company specific prices are annualized in an attempt to represent what the Company's actual experience was or will be, very strange mis-matches can occur which, in a time of volatile prices can create very large–and very inaccurate–differences.

A. THE COMMITTEE'S POWER COST ADJUSTMENTS BETTER APPORTION RISK AND MORE ACCURATELY REPRESENT WHAT NET POWER COSTS WILL BE IN THE RATE EFFECTIVE PERIOD.

The Company is utilizing revenue credit treatment to impose upon ratepayers the large losses it has recently sustained in its wholesale power trading activities. As shown above, these wholesale power trading activities of the Company were entered upon by the Company in pursuit of management's own business strategies and risk/reward calculations and not for revenue credit treatment purposes. Further, the Company in this proceeding has normalized power costs in such a way that they do not accurately or reasonably measure what normal recurring costs and revenues will be during the rate effective period. Given these major problems in the Comppany's recommended net power costs in this proceeding, the Commission is faced with the decision of how best to set reasonable rates for the coming effective rate period.

A. **T<u>he Committee's Base Case Adjustment to the Company's Requested Net Power Costs Complies with the Commission's Reasoning in Prior Rate Cases.</u>**

As shown in argument above under Subsection 1.B. above, there are various ways to adjust the Company's normalized power cost formulations that have been mentioned with approval, and/or utilized by the Commission in prior rate cases which could be considered here. The Committee's "base case" recommends that instead of using the Company's normalized test year prices for short-term firm and secondary transactions the Commission use actual prices for those transactions for the period. We also recommend that Company losses associated with short-term firm transactions be removed from the Company's net power cost formulation because such losses are not normal and should not be expected to be ongoing. Our base case further imputes revenues to certain Company long-term firm sales contracts up to the equivalent current short-term price of these contracts in order to effectively "remove" these contracts from the Company's revenue requirement in this case. This is done because the pricing of these long-term firm contracts was historically so low that it is clear they would never have been approved for revenue credit treatment had they been submitted to the Commission for approval. The Committee's base case also increases thermal plant availabilities beyond levels proposed by the Company.

Were the Commission to decide to keep the Company's normalized price methodology, despite the fact that it violates the Commission-established annualization rules and would not be in keeping with the precedent sat in the last rate case, then the Committee recommends that the Commission also allow out-of- test period adjustments to be made to remove those transactions that will expire within three months of the end of the test period.. Because these expiring transactions are priced so low, and the Company models the external market which it has to buy from so high, the Company introduces what Mr. Falkenberg calls "hypothetical losses". These "hypothetical losses" result because the market rates the Company uses for purchases are not based on reality, but rather "made up" while the expiring sales are made at below market rates. In this case the expring sales transaction revenue is substantially lower than the purchase cost. These hypothetical losses are much larger than any actual losses flowing from those transactions, and larger than any such losses that will occur in the new rate period. This adjustment needs to be made in order to more accurately reflect the objective of normalization, which is to produce prices reflective of the recurring costs and revenues of the new rate period.

None of these proposed adjustments, and none of their methodologies, conflict with prior Commission orders or reasoning. The 1990 orders cites with approval the concept of imputing revenues or costs where necessary to reach more equitable or accurate results, and in the last rate case the Commission adopted the Committee's recommendation in that case to use actual price data instead of the Company's normalized prices for short-term firm and secondary transactions.

B. The Committee's Base Case Adjustment to the Company's Requested Net Power Costs Removes the Normalization and Annualization Errors, Mis-Steps and Faulty Assumptions Existing in the Company's Power Cost Model.

The Committee has found errors, faulty assumptions, and normalization and annualization mis-steps in the Company's power cost model which, when adjusted, reduce the Company's requested net power cost request (after adjusted by Company in this proceeding) from $805.6 million down to $456.7 million. The break-out of these adjustments is as follows:

1. Substitute Actual Prices for Short-Term Firm and Secondary Transactions

Because of the faulty assumptions and numerous annualization and normalization errors in the Company's normalized production cost model, the Committee proposes that the Commission, as it did in the last rate case, substitute actual prices for short-term firm and secondary transactions. This adjustment has a value of -$149.8 million or -$55.3 million on a Utah basis.

2. Remove Losses from Actual Short Term Firm Transactions

Because losses are not normal and are not to be expected to be on-going, and to limit the ratepayers' risks otherwise resulting from the Company's trading activities during the test year, the Committee has removed actual short term firm transaction losses. This adjustment has a value of -$47 million, or -$17.3 million on a Utah basis.

3. <u>Use a six-year Average Plant Availability to More Accurately Reflect Plant Outages.</u> The Committee simply believes a six year average on plant availability and outage rates is more accurate, better reflects plant maintance cycles, and smooths out the occurrences of unplanned outages better than does a four-year average. This Committee adjustment results in an adjustment of -$45.7 million, or $16.9 million on a Utah basis.

4. <u>Correct Generating Plant Capacities</u>

The Wyodak unit should be dispatched at a higher capacity level and the Gadsby units need to dispatch more economically. Making these adjustments reduces the Company's net power costs by -$7.6 million, or -$2.8 million on a Utah basis.

5. <u>Correct the Unreasonably Low Price of the Sacramento Municipal Utilities District Contract.</u> This issue surfaced in previous rate cases. Because the price of this contract is so far below market price, and given the Company benefitted when the contract was first signed by a $94 million up-front payment from SMUD which was never shared with the ratepayers, the standard practice has been to impute additional market based revenues to the SMUD contract. Because market prices have increased substantially since the last rate case, the level of disallowance for this contract pricing should also increase. The Committee proposed the current price for the contemporaneous Southern California Edison contract be used as a basis for imputing additional revenues to the SMUD conract. The resulting adjustment is -$11.5 million, or $4.3 million on a Utah basis.

6. Remove the Cholla Outage.

Applying the deferred accounting treatment requested by the Company in the Hunter outage, the Committee believes that extended outages such as the Cholla outage should be excluded from the test year modeling for outages, otherwise the Company would have the opportunity to double recover its costs for the outage. That is, it could recover the costs of an extended outage through deferred accountring treatment, and it could recover a second time by modeling the impact of the extended outage in its net power cost modeling. Additionally, the Commission should ensure that the Company not be permitted to model the extended Hunter outage in a future rate case. The effect of this adjustment is -$2,9 million, or -$1.1 million on a Utah basis.

7. Correct the Company's Power Cost Model to Accurately Minimize Costs while Satisfying Integrated East-West System Operating Constraints and Efficiencies. As Committee and Division witness Hayet demonstrated in rebuttal testimony, the Company's model inaccurately reflects the cost and operating efficiencies. The effect of these corrections is -$13.6 million, or -$5 million on a Utah basis.

8. Remove the Effect of Certain Long-Term Contracts Whose Revenues Are So Extremely Low that it Can Be Said with Certainty They Would Not Have Received Revenue Credit Approval. The purpose for the revenue credit contract criteria and Commission approval procedure set forth in the 1990 rate case was to shield ratepayers from the untoward effects of wholesale sale contracts being priced so low that they are subsidized by ratepayers during their term. The Committee has identified at least nine long-term firm contracts which clearly fail to meet this ratepayer protective threshold, and which were never approved by the Commission for

revenue credit treatment. Removing the effect of these contracts reduces the Company's net power costs by -$96.9 million or -$36million on a Utah basis. This particular Committee recommendation is affected by whether the Commission decides to adopt the Committee's actual short-term firm and secondary pricing or the Company's normalized prices. If the Commission does adopt our actual pricing proposal, then the value of this adjustment increases to $448.6 million on a total Company basis, or $166.6 million on a Utah basis.

Conclusion

For the many reasons set forth in this Brief, the Committee respectfully urges the Commission to not impose upon ratepayers the losses and risk associated with the Company 's present wholesale power trading activities, and to adjust the Company's net power costs for the effective rate period as the Committee has requested.

DATED this ______ day of August, 2001.

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