WITNESS CCS – 5
EXHIBIT CCS - 5
WITNESS DPU-9
EXHIBIT DPU-9

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application	**:**	**DOCKET NO. 01-035-01**
of PacifiCorp for Approval of its	**:**	**Prefiled Direct Testimony of**
Proposed Electric Rate Schedules	**:**	**RANDALL J. FALKENBERG**
and Electric Service Regulations	**:**	**FOR THE COMMITTEE OF**
	:	**CONSUMER SERVICES AND**
	:	**THE DIVISION OF PUBLIC**
	:	**UTILITIES**

June 4, 2001

TABLE OF CONTENTS

DIRECT TESTIMONY OF RANDALL J. FALKENBERG

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8351 Roswell Road, Atlanta, Georgia 30350.

Q. WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A. I am a utility rate and planning consultant holding the position of President and Principal with the firm of RFI Consulting, Inc. (“RFI”). I am appearing in this proceeding as a witness for the Committee of Consumer Services (“Committee”) and the Division of Public Utilities (“Division”).

Q. PLEASE BRIEFLY DESCRIBE THE NATURE OF THE CONSULTING SERVICES PROVIDED BY RFI.

A. RFI provides consulting services in the electric utility industry. The firm provides expertise in electric restructuring, system planning, load forecasting, financial analysis, cost of service, revenue requirements, rate design and fuel cost recovery issues.

I. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. Exhibit RJF/1 describes my education and experience within the utility industry. I have more than 20 years of experience in the industry. I have worked for utilities, both as an employee and as a consultant, and as a consultant to major corporations, state and federal governmental agencies, and public service commissions. I have been directly involved in a large number of rate cases and regulatory proceedings concerning the economics, rate treatment, and prudence of nuclear and non-nuclear plants.

During my employment with EBASCO Services in the late 1970s, I developed probabilistic production cost and reliability models used in studies for 20 utilities. I personally directed a number of marginal and avoided cost studies performed for compliance with the Public Utility Regulatory Policies Act of 1978 ("PURPA"). I also participated in a wide variety of consulting projects in the rate, planning, and forecasting areas.

In 1982, I accepted the position of Senior Consultant with Energy Management Associates ("EMA"). At EMA I trained and consulted with planners and financial analysts at several utilities using the PROMOD III and PROSCREEN II planning models.

In 1984, I was a founder of J. Kennedy and Associates, Inc ("Kennedy"). At that firm, I was responsible for consulting engagements in the areas of generation planning, reliability analysis, market price forecasting, stranded cost evaluation, and the rate treatment of new capacity additions. I have presented expert testimony on these and other matters in more than 100 cases before the Federal Energy Regulatory Commission ("FERC") and state regulatory commissions and courts in Arkansas, Connecticut, Florida, Georgia, Kentucky, Louisiana, Maryland, Michigan, Minnesota, New Mexico, New York, North Carolina, Ohio, Oregon, Pennsylvania, Texas, Utah, and West Virginia. Included in Exhibit RJF/1 is a list of my appearances.

In January 2000, I founded RFI Consulting, Inc. with a comparable practice to the one I directed at Kennedy.

Q. HAVE YOU PREVIOUSLY BEEN INVOLVED IN ANY REGULATORY COMMISSIONS IN PROCEEDINGS INVOLVING PACIFICORP?

A. Yes, I have appeared in PacifiCorp's (the "Company") last two Utah rate proceedings. In PacifiCorp Docket No. 97-035-01, I testified in support of the Net Power Cost Stipulation ("1997 Stipulation") on behalf of the Division and the Committee. The 1997 Stipulation included most of the modeling and data input adjustments I recommended to my clients.

Last year, I appeared again as a witness for the Committee in PacifiCorp's most recent Utah rate proceeding (Docket No. 99-035-10) where I addressed net power cost issues. In the final order in that proceeding, the Utah Public Service Commission (the "Commission") accepted all of my proposed net power cost adjustments, which totaled approximately $18 million (PacifiCorp system-wide). I also filed testimony on behalf of the Industrial Consumers of Northwest Utilities in UE 111, PacifiCorp's last Oregon rate case. That case was eventually settled. Earlier this year, I filed testimony in PacifiCorp's current Oregon rate proceeding, UE- 116. Hearings in the case were conducted from May 29-31, 2001.

II. INTRODUCTION AND SUMMARY

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. The Committee and Division have asked me to identify and quantify issues related to PacifiCorp's net power costs in this proceeding. The resulting figures are then used as a starting point for additional analysis of net power cost and revenue requirements issues.

Q. WHAT ARE "NET POWER COSTS" AND WHY ARE THEY IMPORTANT TO THIS PROCEEDING?

A. Net power costs are the variable production costs related to fuel and purchased power expenses, net of power sales revenue. The Company has requested $813 million in normalized net power costs, compared to actual net power costs for the test year of $602 million. Regarding the potential impact on Utah revenue requirement, the Company's requested increase in net power costs is the key issue in the case.

Q. WHAT DOCUMENTS AND DATA DID YOU REVIEW TO ANALYZE PACIFICORP'S NET POWER COSTS?

A. I reviewed PacifiCorp's direct testimony, discovery responses, data input files and the modeling assumptions used in the power cost normalization model in order to make recommendations regarding the proper level of PacifiCorp's normalized net power costs for the test year.

Q. WHAT AREAS DO YOU ADDRESS IN YOUR TESTIMONY?

A. My testimony addresses four basic issues:

1. What are the main factors underlying the substantial increase in net power costs alleged to exist by PacifiCorp?

2. Are there any factors reflected in PacifiCorp's requested increase in net power costs that are unrealistic or non-representative of normal conditions?

3. Does the net power cost model, as used by PacifiCorp, produce reasonable estimates of net power costs for use in this proceeding?

4. Are the net power cost model inputs used in this case reasonable compared to those used by the Company or its regulators in prior proceedings?

Q. WHAT ARE THE MAJOR CONCLUSIONS OF YOUR TESTIMONY?

A. My principal conclusions are as follows (all figures on a total Company basis unless noted otherwise):

- The increase in net power costs alleged by the Company is a product of its net power cost normalization assumptions and the use of an adjusted test year that is not representative of either the past or future conditions. The normalized net power costs used by the Company substantially exceed actual test year levels. There is also evidence to suggest that the actual increase in PacifiCorp's net power costs will only be temporary. In fact, the Company's circumstances should improve dramatically around the time that rates from this proceeding go into effect.

- The Commission needs to decide whether to use actual test year wholesale transaction prices (as it did in Docket No. 99-035-10) or to allow an adjustment to acknowledge the changes to the Company's net power costs occurring at the end of the test year. In neither case, would a balanced treatment allow the high net power costs requested by the Company to be made a permanent part of the rate structure. Thus, I offer two alternative adjustments related to the regulatory treatment of wholesale transactions. I understand that other witnesses will also provide the Commission with alternative approaches as well.

- If the Commission strictly follows the precedent set in Docket No. 99-035-10, it should disallow **$126.9 million** in net power costs related to use of actual, rather than flawed normalized prices for short-term firm transactions and secondary purchases and sales.

- According to the precedent established in Docket No. 99-035-10, the Commission should disallow an additional **$71.1 million** in net power costs to remove the effect of short term firm purchases at an average price higher than that of actual short term firm sales.

- If the Commission does not adopt my short-term firm and secondary purchase adjustment noted above and instead adopts the normalized prices proposed by the Company, it should also recognize that PacifiCorp has a number of long-term firm power sales agreements with below market prices that expired by or in December 2000. An alternative adjustment to address this situation is to take the revenue shortfall from these sales as a one-time loss that could be amortized over a period of five years. This would reduce net power costs by **$82.4 million** more than my primary recommendation. This alternative adjustment is only reflected in the Committee's filing.

- While PacifiCorp suggests that the substantial increase in net power costs is largely attributable to the sharp increase in wholesale market prices, in reality, a significant portion of the increase is due to an increase in generator outages. The Company contends that these outages are not indicative of a trend, or a decline in performance, but rather single, one-time events. I recommend an adjustment of **$41.3 million** to provide for a more representative level of generation unit outages in the test year.

- PacifiCorp has included a below market sale to the Sacramento Municipal Utility District ("SMUD") in its test year. This sale has resulted in substantial adjustments in prior proceedings. The Company's proposed adjustment of $2.9 million for SMUD is not consistent with the Commission's Order in Docket No. 99-035-10 because it ignores the fact that the Southern California Edison contract price has increased. An adjustment of **$11.5 million** is consistent with the aforementioned Order.

- PacifiCorp has systematically understated the capacity of many of its generating units though use of incorrect capacity ratings and improper spinning reserve modeling. In particular, it greatly understates the capacity available from the Cholla and Gadsby units. A more proper modeling of spinning reserve and use of more correct capacity ratings for certain generating units reduces net power costs by **$16.5 million**.

- Based on the decision by the Commission to allow deferral of extraordinary Hunter Unit 1 outage costs, I recommend that outage rates in the net power cost model exclude similar extraordinary outages. This results in a reduction to net power costs of **$2.8 million**.

- I have computed a coal price adjustment recommended by DPU witness Burrup. These adjustments reduce net power costs by **$.8 million.**

Q. BASED ON THE ABOVE ADJUSTMENTS, WHAT TOTAL DECREASE DO YOU RECOMMEND TO PACIFICORP'S NET POWER COSTS?

A. Based on these adjustments I recommend that PacifiCorp's net power cost request be reduced by a total **of $279.7 million** on a total Company basis or approximately **$100.4 million** for the Utah jurisdiction.[1] Exhibit (RJF/2) provides a summary of all recommended adjustments. If my alternative

1 This is estimated using a composite Utah jurisdictional allocation factor of 36.93%. These figures reflect Mr. Hayet's adjustments, which I accept.

adjustment related to terminating transactions is adopted, the resulting total decrease in net power costs is $130.6 million on a Utah basis.

The Division and Committee also sponsor other net power cost adjustments. The Division's recommended net power costs includes a coal price adjustment (while the Committee's does not), and uses a different approach for treating wholesale transaction issues. Based on these adjustments, the Division uses a total net power cost model result of $603.7 million, or a reduction of $208.9 million from the Company's filed case. However, Division witness Wilson recommends further reductions to that figure to address the Division's concerns regarding wholesale transactions. Ms. Wilson's proposal supplants the removal of the $71.1 million in losses on short-term firm sales that I discussed above.

The Committee uses a base net power cost figure of $533.7 million, which is a reduction from the Company's filed case of $278.9 million. Committee witness Yankel recommends additional reductions involving wholesale transactions.

III. NET POWER COST ISSUES

Q. COULD YOU PROVIDE AN OVERVIEW OF THE PACIFICORP NET POWER COST ISSUES?

A. The Western electric market in general, and the California market in particular, are in the grips of an extraordinary and unprecedented power crisis. Over recent months wholesale power costs have increased to unprecedented levels and actual physical shortages have occurred in California. PacifiCorp has filed this case, at least in part, to obtain relief from the impact of these increases in wholesale market prices.

In my view, the Company has over-simplified circumstances and overstated the severity of its problems in the power cost area. In its filing, the Company has developed a test period that is not representative of conditions during the period of time when the rates will be in effect and used a combination of non-representative assumptions to increase its costs under the premise of "normalization."

The test year as normalized by the Company is certainly not reflective of conditions as they *actually* occurred. In fact, the projected net power costs (in excess of $812 million on a total Company basis) exceed actual results for the test year ($602 million) by $210 million or 35%.

Nor is the normalized test year likely to be representative of conditions that *will* exist when the new rates are in effect. While the normalized test year shows the Company operating in a power deficit situation, a more realistic assessment shows the Company will soon be in a surplus position. 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 high net power costs by selectively applying a mix of historical and projected data that is representative of neither the past nor the future.

Recent net power forecasts prepared by PacifiCorp demonstrate that the Company will soon experience a dramatic decline in power costs owing to its likely ability to sell surplus power at high prices. In a presentation made by the Company on April 2, 2001 to the parties in Oregon Public Utility Commission Case No. UE-122 (an application for a Power Cost Adjustment), the Company presented a forecast of power costs for the year 2001. Based on this forecast, for the last 5 months of 2001, PacifiCorp's net power costs will drop to an annualized level of $257 million, compared to the test-year actual figure of $602 million. This is only about 32% of the level used in its projected test year result ($812 million) in this case. Even more startling is the Company's projection which shows net power costs going *negative* in October 2001, and totaling a mere $4 million for the last quarter of 2001. I have attached the relevant portion of this presentation as Exhibit RJF/3.

Q. HOW DO THE COMPANY'S NORMALIZED TEST-YEAR NET POWER COSTS COMPARE TO RECENT HISTORICAL DATA?

A. Based on the actual book results, in 1999 the Company's total net power costs were only $431.7 million. This is an amount that is close to the 1998 test year normalized net power costs used in Docket No. 99-035-10. For the unadjusted test year, (12 months ended September 30, 2000) actual total net power costs were $602 million.

Thus, the increase in net power costs is to a great extent a function of the Company's normalization procedure and assumptions rather than an actual on-going occurrence. These normalized figures cannot be verified by auditing PacifiCorp's books and records. Instead, these projections come from its new spreadsheet model, which has replaced PD-Mac.

Q. DOES MORE RECENT ACTUAL DATA SHOW HIGHER NET POWER COST FIGURES?

A. For the year 2000, actual net power costs reported by the Company were in excess of $800 million. However, this higher figure undoubtedly reflects the loss of 400 MW at the Hunter generation station. Use of this net power cost level while also allowing the Hunter deferral could result in over recovery. The Commission has already addressed this issue via the deferral of Hunter outage costs. Now, however, is the time to make an assessment of the best means to permanently address the changes to

PacifiCorp's net power costs. While the most recent historical data does show high actual net power costs, there are indications that this may be a temporary situation.

For this reason, the Commission should be careful not to assume that the Company has experienced an on-going increase in net power costs. In fact, the increase in net power costs has everything to do with the assumptions used by the Company in its normalization of the actual data used in the spreadsheet model, and perhaps even the model itself as Mr. Hayet discusses. I will demonstrate that much of the increase in net power costs is due to temporary circumstances and assumptions that the Company used in its normalization procedures.

Q. WHAT DOES THE COMPANY CLAIM IS THE PRIMARY FACTOR DRIVING THIS NORMALIZED INCREASE IN NET POWER COSTS?

A. The Company alleges that the increase in net power costs is due to increases in the wholesale price for power. This is a very misleading simplification, however. While it is undeniable that wholesale market prices have increased, it does not necessarily follow that PacifiCorp would therefore automatically experience an increase in net power costs. The reason is that PacifiCorp both *buys and sells* power in the wholesale market. If it could sell more power, or buy less, it could conceivably profit from an increase in wholesale prices. In fact, the information presented in Exhibit RJF/3 shows that the Company expects such a scenario to unfold.

If the Company is substantially granted the rate increase it seeks, almost as soon as the higher rates go into effect, it will experience a dramatic decline in net power costs. If that occurs, the Company is under no obligation to seek a reduction in rates to customers. For this reason, I think the Commission should take a very careful look at all of the causes of PacifiCorp's claimed increase in net power costs.

Q. WAS THE SALE OF THE CENTRALIA PLANT A CONTRIBUTING FACTOR TO THE INCREASE IN PROJECTED NET POWER COSTS?

A. By selling its interest in the Centralia plant, the Company had less capacity available for serving native load and off-system sales. Runs that I have performed using the Company's net power cost model show that without the Centralia sale, the Company would have substantially lower net power costs. It is true that the Commission allowed the Company to make this sale. However, regulatory approval does not necessarily absolve the Company from all risks of controversial decisions. I understand that the Division and the Committee opposed the sale on the basis that the Company had understated the market prices for the power necessary to replace Centralia capacity. The Commission should at least consider this fact in its deliberations. Ultimately, it was under management's discretion to go forward with the sale and to obtain replacement power.

Q. ARE THERE ANY OTHER REASONS WHY THE COMPANY IS SHOWING AN INCREASE IN NET POWER COSTS?

A. Yes. The Company has a number of power sales contracts that are now priced well below the normalized market prices it assumes in the net power cost model. Owing to the increase in wholesale prices, this causes net power costs to increase substantially. Exhibit (RJF/4) shows a summary of several power contracts the Company has included in the test year that will end by the end of the year 2001. These sales equate to 633 MW of average demand. Most have prices that are well below the normalized market prices assumed in the Company's filing. Absent these sales, the Company's net power costs would be approximately $413 million less than it projects in the test year. This is highly significant, because unless these impacts are removed, customer's rates will be elevated by costs that no longer exist when the new rates go into effect. Specifically, the Company's power supply position is expected to change from a deficit to a surplus. This should dramatically reduce net power costs (Refer to Exhibit RJF/3).

Q. WHAT ARE THE IMPLICATIONS OF THIS SITUATION FOR THE COMMISSION?

A. I believe that the Commission faces a true dilemma. I understand that over the past decade, the Commission has used historical test years. Post-test year adjustments have typically not been allowed. In my view, the Company is really appealing to a post-test year adjustment by its price normalization of short-term and secondary transactions. The reason is that the Company has used the last four months of data in the test year to develop an “annualization” adjustment to raise market prices up to end of test year levels. However, I believe that this is really a post-test year adjustment in disguise because it is impossible to divorce ourselves from knowledge of current (post-test year) circumstances. For example, had market prices peaked in September 2000, then declined to prior levels, I doubt that anyone would consider it proper to annualize a temporary increase in prices that took place at the end of the year. In fact, we may not even be having a rate case now, had that occurred. It is only because we now believe (based on post-test year events) that market prices will remain high, that one might entertain an argument to annualize the year end price levels.[2]

Another problem facing the Commission is that it is really impossible to consider the recent course of market prices to constitute anything approaching a “known and measurable” change, even as of today. Certainly there is change, but it is impossible to accurately measure it, confidently anticipate its future direction or incorporate its

2 I think it is quite telling that in its Oregon filing (which was filed in late 2000 prior to this request) the Company assumed that average secondary purchase prices for its 2001 test year would be $68.9/mWh. For the chronologically earlier Utah test year, the Company now uses secondary purchase prices of $113.7/mWh. It would seem rather obvious that the Company’s annualized market prices for Utah greatly exceeds the level of prices the Company expected shortly after the end of the Utah test year. This belies the entire concept underlying the Company’s annualization of wholesale prices and vividly demonstrates that this is no “known and measurable” change.

impact on PacifiCorp's net power cost. Indeed, under current circumstances, "normalization" in the face of historically unprecedented circumstances may be a meaningless concept.

In the past, I am certain that problems have existed in all test years examined by all commissions. However, it is quite likely that problems related to the definition of a test year were not nearly as significant, and just as likely to move the final results in one direction as another. We are now confronted with a situation where the difference between one test year and another can be measured in the hundred's of millions of dollars. Fairness requires a solution that matches as close as possible the likely level during the rate effective period.

Q. HOW DO YOU PROPOSE TO ADDRESS THIS ISSUE?

A. Quite simply the Commission has to decide whether it will give consideration to transactions that are terminating or not. If the Commission adheres to its own precedent, it will not consider the terminating transactions. If so, then I believe the Commission should also honor the precedent set in Docket No. 99-035-10, and deny the requested use of "normalized" market prices for short-term firm and secondary transactions in place of actual prices and volumes

If the Commission is willing to abandon precedent and allow the use of normalized market prices, it should also make adjustments to normalize the volumes of these transactions and make adjustments for terminating contracts. I propose and quantify adjustments under both scenarios. However, my primary recommendation is to honor the precedents established in Docket No. 99-035-10. Regarding the Committee's case, these proposals impact the adjustments presented by Committee witness Yankel.

NORMALIZED MARKET PRICES

Q. PLEASE EXPLAIN THE IMPLICATIONS OF FOLLOWING THE PRECEDENT FROM DOCKET NO. 99-035-10.

A. In last year's case, the Commission rejected the use of normalized market prices as applied to short-term firm and secondary transactions. In part, this was based on rejection of the Company's speculative and unproven modeling technique. In the instant case, use of actual prices for short-term firm and secondary transactions would result in a reduction to net power costs of $126.9 million.

Q. DO YOU BELIEVE THAT THERE ARE ANY PARALLELS BETWEEN THE COMPANY'S PROPOSAL TO USE NORMALIZED PRICES IN DOCKET NO. 99-035-10 AND IN THE CURRENT CASE?

A. Yes. In both cases the Company has attempted to use an unprecedented modeling approach to develop what it considers "normalized" market prices. In the last case, the Commission adopted the use of actual market prices. The use of normalized market prices is even more questionable in the current case. To assume that one could develop a reasonable "normal" year-end level of market prices in September 2000, based on the actual information available at the time, is pure hubris. Indeed, it is quite questionable as to whether "normal" conditions actually exist anymore.[3] More likely we are now in a period of supply shortages which is producing relatively high wholesale prices. It may be some time before the market returns to a state of surplus and attendant lower prices.

In any case, 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 PacifCorp, or anyone else. Rather it is a survey reflecting average prices of certain transactions voluntarily provided by certain market participants.

Q. HOW DOES THE COMPANY APPLY THE DOW JONES INDEX?

A. First, the Company uses the Dow Jones figures to establish a "seasonal distribution" of the index over time. This is computed by averaging actual index values from 1996 to 2000 for each month. However, in some cases there is only two months of data available, while in others there is four

3 I believe the Commission's decision to allow deferral of Hunter outage costs is a tacit acceptance of the notion that "normal" conditions do not now exist. Had circumstances been normal, the replacement costs associated with the Hunter outage would likely not have been high enough to justify a special deferral.

months. For example, the average Mid-Columbia ("Mid-C") index for January is based on the average value of the index for January 1997, 1998 and 1999. For, April the average Mid C index is computed from April observations in 1996, 1997, 1998 and 1999. For the average January COB index, only two months of actual data (May 1998 and May 1999) are used. Thus, the Company does not even use the same amount of data in computing the 12 monthly average values. This will certainly affect the computation of the seasonal distribution of prices.

Next, the Company averaged the index prices for the last four months of the test year (June to September 2000) to compute the "normalized" average market price level for the year. This figure is adjusted by the ratio of the average index for those four months relative to the annual average value of the index for the prior years (the seasonal distribution factors). Thus, the seasonal distribution factors impact both the assumed level of the normalized prices over the year, and its distribution by month. Attachment No. 1 is a copy of the analysis used by PacifiCorp to develop the normalized market prices.

Q. DO YOU CARE TO COMMENT ON THIS NORMALIZATION PROCEDURE?

A. Yes. The Company's method is the antithesis of a "known and measurable" change. In fact, more questions are raised in this procedure than answered by it. How do we know that the Dow Jones indices even roughly approximate the prices the Company actually experienced in the market? How do we know that the last four months of the test year (which themselves showed price variations of close to 75%) are representative of "normal" conditions? How do we know that the monthly distribution of this new "annual average" normalized price will follow the patterns established when prices where substantially lower?

For example, the average value of the historical index in June was $16.4/MWh for Mid C. For July the comparable figure was $21.1/MWh (or almost 30% more than June). In the test year, however, the actual index value for June was $181.4/MWh, compared to $122.3/MWh (or 30% less) for July. Thus, the year 2000 values showed a relationship that was opposite of the historical data. Yet the Company assumes for all months other than June to September 2000, the historical relationship between monthly prices will prevail. It assumes, however, that market prices for the last four months of the test year were actually "normal" and does not adjust these prices. Thus, the Company has used four months of unadjusted prices and 8 months of an adjusted or "normalized" price index (that is not even specific to PacifiCorp). This adjustments accounts for a large portion of PacifiCorp's projected net power cost increase.

In addition, the Company did not use any of the monthly values for the year 2000 in computing its seasonal distribution. This suggests the Company views the last 9 months of the test year as "abnormal". Yet the

Company only uses the last four months of the index data to estimate the year end price level.

The Company exercised a great deal of subjectivity in the development of this "normalized price index." For example, in May 2000, the Mid C price index increased to more than 200% of the prior month's (April 2000) value, and more than 300% of the average value of the index for prior Mays. Yet the Company did not include May in the computation of the four months of prices it considered "normal" under the "new order." Had May been included it would have decreased the overall Mid C annual average price by about 10%. A 10% reduction in the normalized price index would reduce PacifiCorp's net power costs by $12 million on a Total Company basis. In addition, if the actual May price had been used, it would have been approximately 50% of the normalized price assumed by the Company.

Q. ARE THERE OTHER PROBLEMS INHERENT IN THIS MODELING PROCEEDURE?

A. Certainly. First, the Company has to construct prices for actual transactions from the normalized index. To do so, it assumes that the ratio of high load and low load hour transactions would remain the same under the new price regime. Further, it assumes that the volumes of transactions would remain the same. Both assumptions seem highly suspect to say the very least.

In the case of the distribution of transactions across hours, the Company's "normalized" price for off-peak power increased by substantially less than the normalized price for on-peak transactions. This suggests that the relative mix of on- and off-peak products would change. Naturally, it would be more profitable to increase off-peak purchases and increase on-peak sales. The Company assumed on-and off-peak sales and purchases would be indifferent to any price changes.

Even more troubling is the assumption that volumes of transactions would remain constant for short-term firm sales. Given that the Company may have been forced to cover these sales with secondary purchases, it may have been more advantageous to reduce or even eliminate these kinds of sales. Had the Company actually known that such an increase in prices would occur, it may not have entered into any of the short-term firm sales it made in the test year. It is likely that, many of these sales were agreed to before the Company experienced the increase in wholesale prices. If the Company assumes for modeling purposes that it can normalize for the change in prices it should also develop normalized sales volumes that are consistent with those normalized price levels. It did not do so, and as a result, the proposed normalization is incomplete and skewed.

In summary, the Company has normalized for only one of many related variables using a highly subjective method that relies on proprietary data of questionable relevance. The normalized price data used does not reflect PacifiCorp's actual purchase and sale prices for transactions it made in past years. The Commission should stay with its precedent established in Docket No. 99-035-10 and use actual Company specific data instead of dubious "normalized" data. If it does so, it is not penalizing the Company because the evidence shown in Exhibit RJF/3 reveals that the Company's net power costs will quickly decline to markedly lower levels.

Q. LETS TURN BACK TO THE DOW JONES INDEX. ARE THERE FACTORS THE COMMISSION SHOULD CONSIDER IN RELYING ON THIS DATA?

A. Yes. Exhibit RJF/5 is a copy of Dow Jones' description of this index. I think the Commission should be reluctant to place such a high degree of reliance on this data as recommended by the Company. I am not questioning whether the Dow Jones index represents a reasonable effort to develop an index. However, it is not based on publicly available trading data, like the Dow Jones industrial average, for example. Rather, this is based on a survey of private transactions, and represents data voluntarily provided by survey participants. Thus, it is subject to the criticism that participants may not accurately reveal all of the pertinent information, or that the survey is non-representative. Since the data is a proprietary product of Dow Jones, there is little that can be done to verify it. Given that a 10% change in the index results in a $12 million-dollar change in net power costs, the Commission is placed in the untenable position of accepting model results that are extremely sensitive to data it cannot verify.

Q. ASIDE FROM THESE DATA INTEGRITY QUESTIONS, ARE THERE ANY OTHER OBVIOUS PROBLEMS WITH THE DOW JONES INDEX AS APPLIED BY THE COMPANY?

A. Yes. In its order in Docket No. 99-035-10, the Commission found that market prices should be different for firm and non-firm products. This was one of the reasons it gave for rejecting the Company's normalized market prices. Dow Jones computes indices for both firm and non-firm transactions. However, PacifiCorp uses the same underlying index to compute prices for short-term firm transactions and secondary sales. Thus, the Company has again ignored the difference in the value of these products.[4] This provides a further basis for the Commission to reject the Company's normalization adjustment.

Q. PLEASE DESCRIBE HOW YOU COMPUTED YOUR RECOMMENDED ADJUSTMENT.

A. I directly applied the precedent from Docket No. 99-035-10, and computed the actual sales volumes and prices for the test year. Using the actual

---

4 The only differences in the firm and non-firm prices used by the Company stems from the questionable application of the historical on and off-peak sales ratios discussed earlier.

prices (See Exhibit RJF/2) results in a reduction to net power costs of $126.9 million on a total company basis.

For secondary sales I used the actual prices for purchase and sale transactions. As Mr. Hayet discusses, the new net power cost model is problematic in that it does not allow for transmission (i.e. power transfers) between the Utah and Pacific Divisions. As a result, it ignores the possibility that the Company would attempt to purchase in markets where prices are relatively low, or sell into markets where prices are relatively high. To address this problem, I use the composite average market price for both divisions. Note that in this approach I am *not* modeling price arbitrage, only the natural tendency of the Company to purchase or sell into the most advantageous market.

LOSSES ON SHORT TERM PURCHASES AND SALES

Q. ARE THERE ANY OTHER ASPECTS OF THE PRECEDENT ESTABLISHED IN DOCKET NO. 99-035-10 THAT HAVE A BEARING THE QUESTION OF WHOLESALE TRANSACTIONS?

A. Yes. In the Order in that case, the Commission also accepted my conclusion that actual monthly losses[5] on transactions were not "normal" or an ongoing situation. The Commission therefore accepted my proposal to eliminate those losses. Based on that precedent, the Commission should also disallow actual losses related to short-term firm transactions. As in the last case, analysis of short-term firm transactions in the Utah division showed that the average cost per MWh for purchases was higher than average revenue per MWh for sales. To address this, I set the Utah purchase prices for each month equal to the sale prices. This eliminates the abnormal losses on these sales and is really equivalent to assuming that the purchases (created by the need to cover the sales) did not take place. This was the same approach I applied in the prior case. This results in an additional reduction to net power costs of $71.1 million on a total Company basis. In the Division's case, my adjustment for short-term firm losses is an alternative to Division witness Wilson's proposals, as she explains in her testimony.

Q. DO YOU HAVE ANY FINAL COMMENTS REGARDING THE ACTUAL PRICE AND LOSS ADJUSTMENTS?

A. The impact of the actual price adjustment depends substantially on whether the Commission accepts my other adjustments and the order of adjustments computed. The figure quoted above for this adjustment was based on running the net power cost *before* my other adjustments had been made. The remaining adjustments I propose generally result in either an increase in capacity available to the Company or a reduction in

5 In this context losses result from short-term firm purchase transactions which on an annual basis had a cost per MW lower than the price of power sold under comparable short- term firm transactions.

load. When PacifiCorp's (much higher) normalized prices for secondary transactions are used, these adjustments are much larger than if actual prices are used.

The loss adjustment *does not* depend on the acceptance of or order of other adjustments because it simply imputes a lower price to specific transactions.

When computed against the Company base case ($812.6 million), these actual price and loss adjustments would result in a decrease to net power costs of $198 million on a total Company basis. It is interesting to note that when applied against PacifiCorp's filed request, the adjusted net power costs would be $614.6 million. This is close to the actual test year value of $602 million and in excess of the amount the Company is now requesting for the 2001 test year in the current Oregon UE-116 case (approximately $600 million).

TERMINATING CONTRACTS

Q. IF THE COMMISSION CHOOSES TO ADOPT PACIFICORP'S MARKET PRICE NORMALIZATION PROCEDURE, WHAT WOULD YOU THEN RECOMMEND?

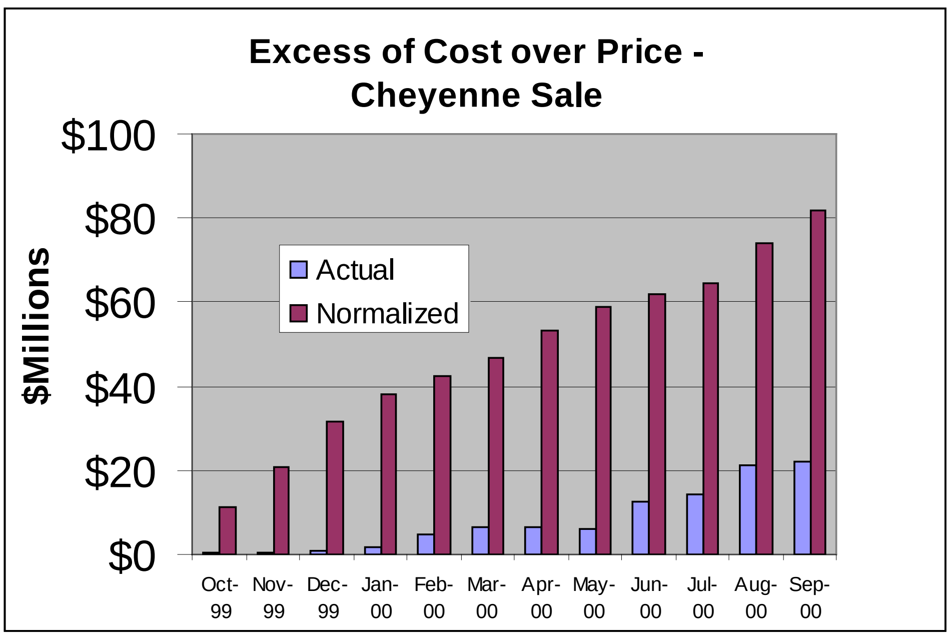
A. If the Commission does so, it will be reversing precedent. If the Commission does alter precedent, I believe it should also consider that the Company has many long-term contracts that expired by or in December

2000. These included the Cheyenne, Clark, Green Mountain, Hinson, Okanogan, PNGC, San Diego Gas and Electric, and WAPA II sales. In nearly all of these cases, the contract prices are well below the assumed market prices used in the Company's power cost model. Thus, adoption of the normalized market prices will create a situation of reflecting *hypothetical* losses on these sales for ratemaking purposes that are well 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. In reality, the Company has created *hypothetical* losses on many of these sales that did not actually occur in the test year and will not occur in the future. This would be a highly inequitable ratemaking result.

Q. EXPLAIN WHAT YOU MEAN BY HYPOTHETICAL LOSSES.

A. In the net power cost model, any energy surplus or deficit is priced at the secondary market price. Thus, the gain or loss on any transaction is the difference between the price of the sale and the secondary market prices. Sales that are priced below the secondary market price input produce a loss. The actual average secondary market price for the test year was approximately $51/mWh. However, the Company's normalized market price input is more than twice that level. Thus, the Company's model is producing losses on sales that greatly exceed the actual revenue shortfall.

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. The figure below compares the actual and normalized losses (on a cumulative basis) from the Cheyenne sale for the test year.



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-term 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 Committees' case.

THERMAL PLANT AVAILABILITY

Q. ARE THERE ANY OTHER FACTORS DRIVING THE INCREASE IN NET POWER COSTS?

A. Yes. Exhibit RJF/6 shows a comparison of the four-year rolling average scheduled and unscheduled outage rates for PacifiCorp thermal generators for 1997, 1998 and 1999. The Company uses this four-year rolling average data to project its net power costs as an input to the net power cost model. As the figures show, the four-year rolling average scheduled outage hours increased by approximately 20% over this period, while the unscheduled outage rates have increased by more than 16%.

Given that these are four-year averages, the implication is that outage rates have increased dramatically in the past few years compared to earlier years. *Exhibit RJF/7shows that on an annual average basis, unscheduled outage rates for PacifiCorp generators increased by 50% from 1994 to 1999.* This is clearly an alarming trend in today's industry characterized by high wholesale prices.

Q. DO THESE INCREASES IN OUTAGE RATES CORRELATE DIRECTLY TO INCREASES IN NET POWER COSTS?

A. Yes. Exhibit RJF/8 shows a computation of test year net power costs based on the Company's case varying only the outage rates. The schedule shows what net power costs would have been in the test year had the Company experienced the same outages as actually occurred in prior years. For example, if the Company experienced the same thermal outages in the test year as actually occurred in 1994, its net power costs would have been only $499 million. Based on 1999 outages, the net power costs were $816.5 million. This is an increase of 60%. Thus, the Company greatly oversimplified the causes of the increase in net power costs when it placed the blame on significantly higher wholesale market prices.

The declining levels of plant availability is directly responsible for a substantial portion of PacifiCorp's projected increases in net power costs. This contributed directly to the projection made by PacifiCorp that shows it will have increase its purchases of high cost wholesale power, and/or reduce off-system sales in the wholesale markets. As discussed above, the impact of this is much larger when measured against the Company's normalized market prices as opposed to actual market prices.

Q. WHAT ARE THE IMPLICATIONS OF THIS INCREASE IN PLANT OUTAGES?

A. As is true in all cases, the Company has the burden of proving that this situation is both prudent and representative of future conditions. In its response to ICNU data requests 8.4, 8.6 and 8.7, in its current Oregon case (UE-116), the Company contended that there is no permanent trend of increased outages. [See attachment No. 2]. Instead, the Company asserts that the increase in outages is the result of "single one of a kind occurrences" that are not indicative of a trend.

Q. REGARDING THIS ISSUE, WHAT IS YOUR RECOMMENDATION?

A. The Commission should not allow an increase in rates of this magnitude, unless it can be shown that the decline in plant reliability is both ongoing and reasonable.

To address this problem, I have used a six-year rolling average to compute outage rates for the net power cost model. The six-year average is longer and will smooth out any purely statistical aberrations. Also, the six-year average will give less weight to the declining performance of recent years when outage rates increased so dramatically due to single occurrence events. This would result in an adjustment of $41.3 million on a total Company basis.

Q. IN THE PAST YOU ACCEPTED THE COMPANY'S USE OF THE FOUR-YEAR ROLLING AVERAGE. PLEASE EXPLAIN YOUR REASONS FOR RECOMMENDING THAT THE COMMISSION ACCEPT THE SIX-YEAR ROLLING AVERAGE IN THIS CASE.

A. I accepted the four-year average in the past because I did not believe it would produce unstable results. Given the much lower market prices that existed at the time, this was reasonable. However, it is now evident that the changes in the four-year average from year-to-year can produce results that can vary by nearly $100 million (on a total Company basis) under current market conditions. This certainly gives reason to reconsider the method of developing this input. Given its significance, it may be preferable to run the model over a larger number of years varying thermal outage rate scenarios in the same manner as the model now simulates varying hydro conditions. I would reconsider my recommendation of a six-year average if the Company can demonstrate that use of a different time period is more reasonable compared to historical plant averages.

Q. THE COMPANY SIMULATES HYDRO OUTAGES BY AVERAGING THE RESULTS OF MANY WATER YEARS. IF IT COMPUTED NET POWER

COSTS FOR THERMAL OUTAGES IN THE SAME MANNER, IT WOULD LIKEWISE INVOLVE AN AVERAGE OF RESULTS OVER A NUMBER OF YEARS. WHAT WOULD BE THE RESULT IF AN AVERAGE OF EACH OF THE SIX-YEARLY OUTPUT RESULTS (SHOWN IN EXIBHIT RJF/8) WERE USED?

A. If one computed net power costs by averaging the six runs based on the thermal outages for each of the prior six years, it would result in an average net power cost of $700.4 million, or $112 million less than the Company's request. When the six-year rolling average of outage rates is applied against the Company base case, the resulting net power cost would be $721 million. Therefore, if the Company modeled thermal outages in the same manner as it models hydro, the resulting net power costs would be about $20 million lower. This demonstrates that thermal outages may now be even more important than hydro variations, and modeling methods should be developed to address this problem. Mr. Hayet discusses this situation in more detail in his testimony, and recommends modeling changes to address this issue.

SMUD CONTRACT

Q. ARE THERE ANY OTHER ADJUSTMENTS YOU RECOMMEND RELATED TO LONG-TERM POWER CONTRACTS?

A. Yes. In the rate case last year (Docket No. 99-035-10), the Commission made a revenue imputation for a contract with the Sacramento Municipal Utility District ("SMUD") on the basis that the prices were unreasonably low:

> **In 1987, the Company entered into a long-term (through 2014) contract with the Sacramento Municipal Utility District (SMUD) under the terms of which SMUD acquires electricity from the Company at a rate of $16.85 per MWH. This rate was below-market in 1987, but the contract, according to the Company, results from a complex set of transactions which, among other things, yielded for the Company an up-front payment from SMUD of $94 million. That amount, however, was retained by the Company rather than benefiting ratepayers through reduced rates. Imputing revenues to compensate for the below-market contract therefore has been common in several states since 1987. . . .**
>
> *** * * ***
>
> **Since the contract was below-market when signed, the task before us is to find a rate, contemporaneous with the contract date, to use as the basis for revenue imputation. (**Utah Public Service Commission Docket No. 99-035-10, Final Order, pages 43-44.)

The Commission settled on imputing a price based on the Southern California Edison ("SCE") contract, which was negotiated at the same time. In addition, the Commission imputed additional revenue to six other contracts that had prices it viewed as unreasonably low.

Q. HAS THE COMPANY MADE AN ADJUSTMENT TO ITS TEST YEAR TO REFLECT THE SMUD REVENUE IMPUTATION?

A. Yes. In the Order in the last Utah Case (Docket No. 99-035-10) the Commission decided to impute a price of $37/MWh to the SMUD contract. The imputation was based on the price of the SCE contract during that test period. The SCE contract was selected because it was originally negotiated about the same time as the SMUD contract. However, I think it would be incorrect to read the Order as committing the Commission to invariably use the $37/MWh figure. Specifically, the Commission allowed for use of a changed price in the SCE contract that resulted when the contract was renegotiated.

In its filed adjustment the Company ignores the fact that the *SCE contract has an adjustable price*. The current (test year) price for the SCE contract is $47.7/mWh. If the Commission continues to follow its Order in Docket No. 99-035-10, it should use a price of $47.7/mWh price to compute this adjustment. That price results in an $11.5 million adjustment on a total Company basis. This is almost one and a half times larger than the adjustment filed by the Company.

CAPACITY RATING/SPINNING RESERVE ISSUES

Q. PLEASE PROVIDE SOME BACKGROUND CONCERNING THE SPINNING RESERVE/CAPACITY RATING ISSUE AND ITS IMPORTANCE TO PACIFICORP'S PROJECTED NET POWER COSTS.

A. PacifiCorp has a history of understating the capacity of its generators in its net power cost studies. In its filing in Utah Docket No. 97-035-01, PacifiCorp reduced the capacities of several plants below their maximum dependable capacity. The Company said it needed to make these adjustments to reflect spinning reserves. In effect, the Company de-rated its system by 115 MW.

Although I agreed that spinning reserve requirements impact dispatch decisions and generally lower the efficiency of system operations, it was not appropriate to reflect these considerations by a simple capacity deration to the degree that PacifiCorp had assumed.

In Docket No. 99-035-10 (the 1999 Utah rate case) the Company understated the capacity of several generators whose capacity had been increased by upgrade projects. According to Mr. Widmer's rebuttal testimony, the Company inadvertently overlooked these increases in capacity. In that same case, the Company also understated the capacity of Cholla Unit 4, due to an input mistake in its spinning reserve modeling.

In the last Oregon case (Docket No. UE-111), the Company also understated capacities of several units due to inappropriate spinning reserve modeling. Again, the Company used deration of capacity as a means of representing spinning reserve.

In the current Oregon case (Docket No. UE-116) the Company has admitted that it understated the capacity of the Colstrip and Gadsby Units because Mr. Widmer used outdated capacity assumptions.

Finally, the Company has continued to use its spinning reserve deration in the current Utah rate case.

Q. WHY IS REDUCING CAPACITY A POOR WAY OF REPRESENTING SPINNING RESERVES?

A. This issue was first examined in the 1997 rate case. Spinning reserve requirements are usually accounted for by the dispatching of *more* generating units at any point in time than is required to serve load, and not by reducing the capacity of individual units. In emergency conditions, operators will "dip into" these reserves to maintain system stability. Thus, spinning reserves are manifested by an increase in system capacity online and a corresponding reduction in the individual loadings of units. This in turn increases average heat rates. Due to other modeling changes (that I recommended and PacifiCorp accepted in Utah Docket No. 97-035-01) this effect was already accounted for in PD-Mac, the model the Company was using at the time. Thus, there was no reason to reduce unit capacities to account for spinning reserve.

During our discussions, PacifiCorp eventually acknowledged in the 1997 rate case that it may have overstated the impact of spinning reserves. The Company also indicated that in the Pacific Division, hydroelectric resources sufficiently satisfied its spinning reserve requirement. Although PacifiCorp's database originally showed 115 MW of capacity derations for spinning reserves, the Net Power Cost Stipulation in Utah Docket No. 97-035-01 reduced that number to 30 MW, all at PacifiCorp's high cost coal unit, Cholla Unit 4.

In its Utah filing in 1999 (Docket No. 99-035-10), PacifiCorp initially used a 40 MW deration, instead of 30 MW. However, in Mr. Widmer's rebuttal testimony, the Company agreed to correct this apparent input mistake. At the same time, the Company agreed to correct the sizeable capacity understatement that it originally overlooked.

Q. HAS PACIFICORP FILED THIS CASE USING THE SPINNING RESERVE ADJUSTMENT IT AGREED TO IN THE LAST TWO CASE?

A. No. In Dockets Nos. 97-035-01 and 99-035-10, PacifiCorp agreed to reduce its spinning reserve capacity deration adjustment from 115 MW to 30 MW in its spinning reserve calculations. In this case the Company has now largely returned to its prior spinning reserve modeling, which assigns much larger amounts of spinning reserve and applies it to more units than Cholla Unit 4.

Q. WHAT HAVE YOU DONE IN LIGHT OF THE PACIFICORP HISTORY OF UNDERSTATING THE CAPACITY OF GENERTORS IN NET POWER COST STUDIES?

A. Because this has been a persistent source of controversy, I have examined the hourly generator logs for all PacifiCorp resources, and compared those to the inputs used in the net power cost model. Based on this review I have determined that the Company has *systematically understated* the capacities of many resources, even some which it does not claim to be used for spinning reserve purposes. In addition, I have examined the issue of spinning reserve in more detail and developed an approach that relies more on the Company's actual data from generator logs.

Q. PLEASE START WITH YOUR DISCUSSION OF THE FIRST CATEGORY OF CAPACITY UNDERSTATEMENTS. WHICH NON-SPINNING RESERVE RESOURCES HAVE HAD THEIR CAPACITY UNDERSTATED IN THE NET POWER COST MODEL?

A. The Company has understated the capacity of several generators. For example, the Company models its share of Colstrip units 3 and 4 as 140 MW. Based on year 2000 generator logs, the Company actually was able to obtain generation in excess of that level for more than *4500 hours* during the year. In the current Oregon case, the Company has conceded that the rating for Colstrip is understated in its net power costs models.

Results are similar for Wyodak. While PacifiCorp's share is included in the spreadsheet model as 268 MW, in reality, PacifiCorp's Wyodak generation exceeded that level for more than *7000 hours* in the year 2000. Based on review of generation logs, I recommend an increase in the capacity of Wyodak of 14 MW.

Q. DO YOU STILL BELIEVE THE 30-MW DERATION OF CHOLLA IS JUSTIFIED AS A SPINNING RESERVE ADJUSTMENT?

A. No. Now that I have examined the most recent generator logs, I have determined that a 30 MW reduction in Cholla capacity is excessive. In fact, the unit exceeded the 350 MW output (which is the capacity for Cholla after a 30 MW deration for spinning reserve) for more than *2900 hours* (or the equivalent of four months) in the year 2000. This clearly demonstrates that the Company loses very little generation from this resource due to spinning reserve requirements.

Q. ARE THERE OTHER GENERATORS WHOSE CAPACITY IS UNDERSTATED IN THE NET POWER COST MODEL?

A. Mr. Widmer has effectively removed Gadsby Units 1 and 2 from the dispatch sequence for all but three summer months. Thus, he assumes that these units can only provide generation during the three summer months. I believe that this modeling is a hold over from the past when the Company seldom ran all three units at the Gadsby plant, except in the summer for voltage support. The increase in market prices has made it more economical to run the Gadsby units year round. In Mr. Widmer's modeling, this would be impossible since Units 1 and 2 are not allowed to run. Review of actual data shows these units have operated outside of the summer months. Mr. Widmer recently agreed to correct this error in the current Oregon case.

Mr. Widmer also limits the availability of all three Gadsby units throughout the year through use of a generation availability factor that overrides the historical input data. It appears that this input was computed to limit the operation of the plant to 4 days per week. Again, this is a hold over from prior years when the plant's operation was not economical due to lower market prices. I believe it is more appropriate to allow the model to determine the actual level of operation.

Q. HAVE YOU REVIEWED ANY OTHER DATA THAT SHEDS LIGHT ON THE SPINNING RESERVE ISSUES?

A. Yes. In the current Oregon case the Company has produced a calculation of actual spinning reserve allocations to specific generators. I reviewed this information and determined that it clearly overstated the impact of spinning reserve requirements on the availability of generation from PacifiCorp's thermal resources by as much as 75%. As previously discussed, Mr. Widmer's modeling of the operation of the Gadsby plant also has a major impact on spinning reserve. Owing to its higher cost, it would make more sense to meet spinning reserve requirements from Gadsby whenever possible, and only use other plants if Gadsby cannot meet the entire requirement.[6] In fact, review of the available data does show that in the past six months, spinning reserves assigned to Gadsby increased and that the plant was not shut down at the end of the summer. Based on this data, I have developed an approach to assign 45 MW of

---

6 Some utilities do require that spinning reserve be allocated to a number of resources.

PacifiCorp's capacity to spinning reserve.[7] This is an increase of 50% from the prior two cases. In accordance with actual data, this assigns the majority of spinning reserve to Gadsby.

Q. WHAT EFFECT DO THESE CAPACITY ADJUSTMENTS HAVE ON PACIFICORP'S NET POWER COSTS?

A. This correction reduces the net power costs in the Company's net power costs by **$16.5** million. Again, this adjustment would be much larger if it were run against the Company's normalized market prices.

EXTRAORDINARY OUTAGES

Q. ARE THERE ANY OTHER ADJUSTMENTS YOU RECOMMEND?

A. Yes. Recently the Commission decided to grant the Company the right to defer costs stemming from the Hunter outage. This is an important policy decision because it implies that customers may be expected (during periods of high market prices) to absorb costs related to such extraordinary outages. If that is the case, then normalized net power costs should not include any provision for such very long outages. In the database used by the Company, however, similar long or non-recurring outages have been included. The most substantial event of this type was

7 This was developed by using 25% of the amount of spinning reserve assigned to coal plants and 100% of the levels assigned to Gadsby in the Oregon analysis discussed above.

an outage in excess of 3000 hours for Cholla Unit 4 in 1996. This outage started on March 9, 1996 and lasted until July 14, of the same year. This period of time, (127 days) is quite comparable to the duration of the recent Hunter Unit 1 outage. In the past the Company bore the risk of these outages if they occurred between rate cases, although they were factored into the computation of average outage hours in the net power cost model. Because the Commission has now granted a deferral of the costs of such long outages, the impact of this outage should be removed from the net power costs. This results in a reduction in net power costs of $2.8 million on a total Company basis.

Q. DO YOU HAVE ANY OTHER ADJUSTMENTS?

A. Yes. I have computed a reduction to the Dave Johnston coal cost of $.8 million based on the recommendations of Mr. Burrup.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.