BEFORE THE

PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of	**:**	**Docket No. 07-035-93**
Rocky Mountain Power for Authority	**:**	
To Increase its Retail Electric Utility	**:**	**Direct Testimony of**
Service Schedules and Electric Service	**:**	**Philip Hayet**
Regulations, Consisting of a General	**:**	**for the Committee of**
Rate Increase of Approximately	**:**	**Consumer Services**
$161.2 Million Per Year, and for	**:**	
Approval of a New Large Load	**:**	
Surcharge		

APRIL 7, 2008

Table of Contents

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Philip Hayet, 215 Huntcliff Terrace, Atlanta, GA 30350.

Q. PLEASE STATE YOUR OCCUPATION, EMPLOYMENT, AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am an Electrical Engineer, and work as a utility regulatory consultant. I am President of Hayet Power Systems Consulting ("HPSC"). I am appearing in this case as a witness on behalf of the Utah Committee of Consumer Services ("Committee").

Q. BRIEFLY DESCRIBE THE NATURE OF THE CONSULTING SERVICES PROVIDED BY HPSC.

A. HPSC provides consulting services in the electric utility industry. Our clients primarily include state agencies. The firm provides expertise in resource planning and fuel supply issues. Current clients include the Georgia and Louisiana Public Service Commissions, and the Utah Committee of Consumer Services.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND.

A. I graduated from Purdue University in 1979 with a B.S. degree in Electrical Engineering, and in 1980, I received a M.S. degree in Electrical Engineering from the Georgia Institute of Technology, with a specialization in Power Systems.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND APPEARANCES.

A. I have more than twenty years of experience in the electric utility industry in the areas of generation resource planning, economic analysis, and rate analysis. I have participated in and filed testimony concerning numerous cases involving PacifiCorp net power cost issues. My qualifications and appearances can be found in Exhibit CCS 5.1 attached to my testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A**.** I, along with Committee witness Randall J. Falkenberg, address modeling issues related to PacifiCorp's calculation of Net Variable Power Costs ("NVPC") using its Generation and Regulation Initiatives Decision ("GRID") model for the projected test period, January 1 through December 31, 2008. All of the adjustments that I propose will be incorporated into Mr. Falkenberg's Table 1.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I have identified and quantified the following adjustments and issues regarding PacifiCorp's GRID modeling in this proceeding:

Long Term Firm (“LTF”) Contract Adjustments

- Sacramento Municipal Utility District (“SMUD”) contract
- Sunnyside qualifying facility (“QF”) contract
- Biomass QF contract
- Schwendiman QF contract

Monthly Outage Rates Adjustment

The Company computes generating unit forced outage rates that it models in GRID using actual data covering a four-year historical period. Instead of using the more common utility industry practice of creating annual average forced outage rates from this data, and using that in its production cost modeling, the Company creates average monthly forced outage rates. This approach is contrary to standard industry practice and we recommend the use of annual average forced outage rates. Mr. Falkenberg has computed an adjustment based on the use of annual average forced outage rates, which is included in his Table 1.

Deration of Unit Capacity, Heat Rate, and Uneconomic Generation Adjustment

We have identified several modeling issues including improper deration of unit capacity, the use of incorrect heat rates, and uneconomic generation which occurs in GRID. The deration and heat rate issues are easily correctable, and we have made adjustments to properly account for those problems. We have also identified a problem in which GRID commits generating units in a sub-optimal manner, which as I will discuss stands in stark contrast to the objectives of a production cost model. Mr. Falkenberg has developed adjustments for each of these items, which he also discusses in his testimony, and the results are found in Table 1 in his testimony.

II. SMUD CONTRACT MODELING ADJUSTMENT

Q. PLEASE DISCUSS THE CIRCUMSTANCES SURROUNDING THE SACRAMENTO MUNICIPAL UTILITY DISTRICT ("SMUD") CONTRACT.

A. The SMUD contract is a 30-year sales contract scheduled to expire in 2014, whereby PacifiCorp supplies SMUD 350,400 MWh of on-peak power (at a rate of 100 mW per hour).[1] The 2008 contract price is $21.46/MWh, based on a formula tied to the average cost of Jim Bridger fuel and O&M costs (see PacifiCorp response to DR CCS 13.9). This price is substantially below market. In this proceeding, the Company proposes to price the contract in GRID at $37/MWh rather than the actual contract price. This treatment is based on decisions the Commission made in the 1999 and 2001 General Rate Case proceedings, Docket Nos. 99-035-10 and 01-035-01, respectively.

In the 1999 proceeding, the Commission required additional revenues to be imputed on the basis that the contract prices charged to SMUD were unreasonably low. In its Final Order in the 2001 case, Docket No. 01-035-01, the Commission summarized the history of this issue:

> *As in the immediately preceding general rate case for this Company, Docket No. 99-035-10, this Commission is asked to*

[1] In GRID, PacifiCorp specifies the SMUD energy value as 351,400 MWh. The Company incorrectly included more energy than the actual contract energy, because it adds energy for the leap day in February. Mr. Falkenberg addresses this issue in his testimony.

> *impute revenues to a 1987 long-term firm wholesale contract with SMUD to counter the contract's adverse impact on the net power cost portion of jurisdictional revenue requirement. In that Docket, the Commission did order imputation because the contract obligated the Company to serve SMUD at $16.85 per MWh at the time it was entered, a rate much below the then-current rate for power. In addition, SMUD paid the Company $94 million at the outset of the contract that it retained and was not used to benefit ratepayers. Nor was this the first time the imputation had been made. In connection therewith, both here and in other PacifiCorp jurisdictions, a contract with Southern California Edison (SCE) entered at about the same time for $42 per MWh had been considered an appropriate benchmark for imputation. The evidence in Docket No. 99-035-10 showed that the SCE contract had been renegotiated to a rate of $37 per MWh due to structural changes in the wholesale market. In other words, the Commission recognized that wholesale prices, which had fallen, were now on a different path. This, and the fact that the renegotiation was closer in time to the test period, persuaded the Commission to select the $37 rate as the basis for imputation, a rate indicating how such a contract might perform over time.* **<u>Re PacifiCorp</u>, UPSC Docket No. 01-035-01, Report and Order at 24-25 (Sept. 10, 2001).**

Q. HAVE ANY SUBSEQUENT CASES ADDRESSED THIS ISSUE?

A. The settlements in the recent cases did not specifically address the issue of what the proper price for SMUD should be.

Q. WHY SHOULD THE COMMISSION RE-EXAMINE THE SMUD CONTRACT ISSUE FOR THIS CASE?

A. There are three important reasons why the Commission should address this issue now. <u>First</u>, wholesale power prices have continued to increase since the adoption of the Utah order in the 2001 case. Indeed, the SCE contract that was the basis for the $37/MWh was subsequently renegotiated and the most recent contract prices have been much higher. In 2001, the price was $84.5, and since 2002 the price has been $60/MWh. Second, the SCE contract terminated in September 2006, and since SCE was selected by the Commission as a prudent benchmark contract contemporaneous to SMUD, the basis for imputing the price of $37/MWh no longer exists. Consequently, the Commission should decide again on the proper basis for handling this issue for the remaining seven (7) years of the SMUD contract.

Finally, the $37/MWh figure was questionable from the start, and did not actually reflect prices used in the SCE contract. In fact, in 2001 the Commission itself questioned the basis for the $37/MWh rate but did retain that as the proxy price because it believed it to be compensatory, as will be discussed later. Review of the final order in Docket No. 01-035-01 suggests that the Commission's basis for selection of the $37/MWh price is no longer appropriate and that the Commission invited parties to address this issue again in subsequent cases. The Commission's Order stated, "Consequently, we accept the $37/MWh figure and await further argument in a future case." **(PacifiCorp, UPSC Docket No. 01-035-01, Report and Order at 25, Sept. 10, 2001)**

Q. WOULD IT BE PROPER TO BASE REVENUES FROM THE SMUD CONTRACT ON THE CURRENT SMUD CONTRACT PRICE?

A. No. The actual SMUD contract price ($21.46/MWh in 2008) is not compensatory. The Company entered into this contract after receiving an up-front payment of $98 million, which it retained for itself.[2] As a result, PacifiCorp shareholders, not ratepayers, should bear the risk of this contract until it expires. Exhibit CCS 5.2 provides a copy of the Company's response to CCS DR 6.28, which explains the history of the transaction as of 1991. This was in the form of a letter from Mr. Gregory Duvall to a regulatory Commission in another state.

Noteworthy in this history is that when the Company first entered into the SMUD agreement, it appears that the Company expected it would obtain low cost power from BPA in concert with the SMUD sale, and would assign that power to SMUD. (Response to CCS DRs 6.29 and 6.30) The low cost power from BPA became available through an agreement between BPA and PacifiCorp that settled a lawsuit related to PacifiCorp's interest in the uncompleted WNP-3 nuclear unit. The Company, however, ended up deferring the right to accept the BPA power, and in 1996 forfeited those rights when it let the agreement with BPA expire.

As a result, the Company failed to obtain the low cost power that it could have used to supply the SMUD contract, but kept the $98 million up-front payment, and ended up supplying the SMUD contract through other available system resources.

[2] The Commission's orders mention a $94 million payment, while the Company's response to DR CCS 6.28 providing the history of the SMUD contract mentions the payment was $98 million.

Subsequently, the Commission began imputing a price to the transaction, as discussed above.

Q. IS THE $37/MWH PRICE COMPENSATORY AT THIS TIME?

A. No. This price is substantially below current wholesale market prices, and the revenues derived based on this price are insufficient to cover PacifiCorp's cost to serve the contract. The SMUD contract is modeled in GRID as a call option for on-peak power. This means that the model optimizes the delivery schedule of the energy sold to SMUD, under the terms of the contract, in order to maximize the benefit to SMUD. Removing PacifiCorp's obligation to serve SMUD from within GRID, and removing the revenues based on the $37/MWh that have been imputed for the sale to SMUD results in a savings to PacifiCorp's NVPC of $13.7 million. In other words, at the cost that it takes to serve the SMUD contract, PacifiCorp's customers would have to receive an additional $13.7 million in revenue just to break even on the contract. Therefore, an imputed price of $37/MWh is not sufficient for PacifiCorp's customers to even recover the cost to serve the SMUD contract.

Q. PARTIES HAVE RAISED THIS ISSUE IN OTHER CASES. HOW HAS THE COMPANY RESPONDED?

A. The Company has made various arguments. In the most recent Washington case, Company witness Mark Widmer made two primary arguments: 1) Re-pricing

SMUD, just because it has been below market is inequitable. He argued that other low cost contracts such as Mid-C could just as well have been re-priced for the same reason.[3] 2) He also argued that the SCE contract was renegotiated, thus the "original" SCE contract remains the relevant comparison.[4]

Q. HOW DO YOU RESPOND TO THESE ARGUMENTS?

A. To address the Company's first point, it is important to understand that the history of the SMUD transaction was far different than that of the Mid-C contract. In effect, the Company provided SMUD with a long term below market source of power in exchange for an up-front payment. This entire transaction was undertaken to resolve a problem related to an unregulated nuclear project cancellation, as discussed above. The Company also knew from the beginning that the SMUD contract price was below market.[5] None of these circumstances are present with the Mid-C contract. Unless the Commission makes an adjustment to address the effects of the SMUD contract, the Company will have retained the benefits of the up-front payment, while ratepayers will continue to pay the high cost of serving the below market contract. There is no basis for assuming that the conditions that existed with regard to the SMUD contract are equivalent to the conditions associated with the Mid C contract. In the case of SMUD, it is a matter of prudence and reasonableness of costs. It is not prudent, or reasonable for

[3] Rebuttal Testimony of Mark T. Widmer WUTC Docket Nos. UE-061564/UE-060817, page 32, http://www.utahpower.net/Regulatory_Testimony/Regulatory_Testimony72406.pdf
[4] Id.
[5] Id, page 31.

PacifiCorp to sell power below market, at ratepayer's expense, in exchange for an up-front payment that only benefited the shareholders.

The Company's second argument is even more dubious than the first. The fact is that the "original SCE contract" (the $37/MWh contract) as the Company refers to it, was never relevant to anything. As the Commission's 2001 order points out, the contract had actually been renegotiated *downward* from $42/MWh to $37/MWh in 1999. However, the $37/MWh price was never actually used for contract pricing, as it was renegotiated again *upward* to $60/MWh. Further, the Commission discovered after adoption of the $37/MWh price in 1999 that even that price was in error. Instead, the actual test year contract price for the 1999 test year was $49.42/MWh:

> *PacifiCorp informs us that power cost data in Docket No. 99-035-10 contains a test-year SCE contract price of $49.42, which, it alleges, should have been used if the intention was to base imputation on a test-year contract price.*
>
> *We seek a reasonable basis for imputation, once we decide an imputation must be made. In the previous Docket, $37 was such an amount, because it was the most current contract price debated on the record and it recognized structural changes in the wholesale market. No party advocated the test year figure of $49.42 the Company now calls to our attention. In fact, no party mentioned the figure in that Docket and we were not aware of it.*
> **Re PacifiCorp, UPSC Docket No. 01-035-01, Report and Order at 24 (Sept. 10, 2001)**

In fact, the $37/MWh was never really a relevant price for SCE. In 1999, the contract price was $49.42/MWh as discussed above. In 2000 and 2001, the actual contract prices were $47.5/MWh, and $84.5/MWh, respectively. From 2002 to 2006, the SCE contract price was $60/MWh. In the end, the $37/MWh was never used for anything other than ratemaking purposes and was itself the result of a contract renegotiation of the earlier SCE contract. While the Commission was satisfied to not adjust the price in its September 2001 order, the Commission stated that its real objective was to find a contract price that was *compensatory*, which, at the time, the Commission believed the $37/MWh to be. Indeed, the Commission even indicated it would await further arguments on this issue in future cases.

> *Our objective is to impute revenues to the SMUD contract to make it* <u>*compensatory*</u>*. The only proposals before us are to apply $37 or $47.70 to the SMUD contract. After the testimony and argument in this case, there are enough questions about the SCE contract as an appropriate reference that we will not depart from our previous decision by increasing the imputation to $47.70. Consequently, we accept the $37 per MWh figure and await further argument in a future case.* (Underline added for emphasis). **<u>Re PacifiCorp</u>, UPSC Docket No. 01-035-01, Report and Order at 25 (Sept. 10, 2001)[6]**

Given that currently, much higher market prices for power now exist, the $37/MWh price is clearly no longer compensatory.

[6] The $47.70 price was based on another proposal that the Commission had to consider in the 2001 docket for pricing the SMUD contract. It was the 2001 SCE contract rate in place during the 2001 rate case test period.

Q. HOW MIGHT THE COMMISSION ADDRESS THIS ISSUE AT THIS TIME?

A. The simplest approach would be to remove SMUD from GRID. This would automatically have the effect of imputing revenue at the current market price and would therefore be *compensatory*. The assumption with this approach would be that any cost to serve the contract would be perfectly matched with any revenue received from SMUD and therefore, PacifiCorp customers would not incur any additional costs as a result of PacifiCorp serving the SMUD contract. Removing the SMUD contract in GRID would produce a reduction to NVPC of $13.71 million compared to the GRID run supported by the Company and included in Mr. Duvall's Exhibit GND-1S to his Supplemental Direct Testimony.

Q. WHAT DO YOU RECOMMEND THAT THE COMMISSION DO TO RESET THE SMUD PRICE IN THIS RATE CASE?

A. Since the $37/MWh figure was originally accepted, the Company has continued to increase the price charged to SMUD. The Company's responses to CCS 13.8 and 13.9 show that in 1999, the Company charged SMUD $15.29/MWh, and in 2008 the Company is expected to charge an increased amount of $21.46/MWh. As a result, the Company is now collecting more of the cost of the SMUD contract than it did when the $37/MWh was first approved for revenue imputation. Thus, the amount of the Company's disallowance has gotten smaller, while the cost of serving SMUD has increased substantially.

In the 1999 case, the Company estimated market prices to be approximately \$20.57/MWh and estimated the SMUD contract revenue price to be \$14.66.MWh.[7] In this case, the market price can be viewed as the cost that PacifiCorp would have to be paid in order to break even. Without imputing any additional revenues, the customers would have suffered a loss for each MWh sold of \$5.91/MWh (20.57 – 14.66). Therefore, at that time, the \$37/MWh imputed price effectively shielded customers from the energy cost of serving SMUD, and provided customers with additional revenues for each MWh sold of \$16.43/MWh (37 – 20.57). These additional revenues effectively provided customers capacity payments to compensate for the fact that the SMUD contract required that firm capacity be available to make the sale. In other words, for resource planning purposes, PacifiCorp has to include the SMUD load as a firm load obligation as it determines how much capacity it needs to satisfy its system requirements. In recognition that PacifiCorp received an up-front payment of \$98 million, the imputed revenues in 1999 effectively cost PacifiCorp \$22.34/MWh for each MWh sold to SMUD (37 – 14.66).

In contrast, by 2008 the market price for power has increased substantially based on GRID results. Based on the 2008 test period, the true cost of serving SMUD is \$76.02/MWh for each MWh sold. This is the actual energy rate that PacifiCorp would have to be paid in order to break even on serving the SMUD contract. This is based on the annual difference in cost between GRID runs with and without the contract, divided by the annual energy sold to SMUD, and it ignores for the moment any revenues that SMUD has to pay under the contract.[8] At present, this means that customers are absorbing far more of the cost of serving the contract than the Company. Since the annual cost to serve SMUD is actually $76.02/MWh, and customers through the regulatory process receive imputed revenues of $37/MWh, then customers incur losses of $39.02/MWh for each MWh sold (76.02 – 37). Since revenues have been imputed that the Company is responsible for, it also incurs losses. However, the Company's losses are far lower than the customers, $15.54/MWh for each MWh sold (37 - 21.46, which is the imputed price less the actual 2008 SMUD contract price).

Continuing to impute revenues based on $37/MWh, means that as market prices have increased, the cost to customers from SMUD has increased also, while at the same time, the disallowance imposed on the Company has gotten smaller. As a matter of fairness, the Commission should at least require that the disallowance it imposes should reflect the fact that the Company obtains higher revenue each year from the contract. Consequently, I recommend that the Commission index the imputed price (the heretofore $37/MWh) to the contractual SMUD price. As the

[7] Thus, there was a small mismatch between the actual contract price and that assumed in the 1999 case.
[8] $26,713,389 / /351,400 MWh = $76.02/MWh

contract price increased from the $14.66/MWh expected in the 1999 case to $21.46/MWh for 2008, or $6.8/MWh, I recommend the imputed price be increased by the same amount. This results in an imputed price of $43.8/MWh (37 + 6.8). This produces an additional disallowance of $2.38 million (350.4*(43.8-37)) on a total Company basis. The additional disallowance of $2.38 million is based on the fact that the Company had already built into its GRID results imputed revenues of $37/MWh for each MWh sold. However, the disallowance per MWh that the Company will incur will be the difference between the actual revenue rate it will receive from SMUD in 2008, $21.46/MWh and the revised imputed revenue rate of $43.8/MWh for a total of $7.8 million (350.4*(43.8-21.46)). This is at least a little more equitable to customers because, based on the way this new adjustment was designed, it is exactly equal to the disallowance the Company first encountered in 1999 of $7.8 million (350.4*(37-14.66)). Mr. Falkenberg reflects this adjustment on his Table 1.

III. MONTHLY OUTAGE RATES ADJUSTMENT

Q. PLEASE EXPLAIN THE NATURE OF THIS ISSUE?

A. At the outset, when the Company prepared to project NVPC using GRID covering the 2008 calendar year test period, it had to settle on numerous data assumptions in order to properly model its system. One of the important data assumptions was the generating unit forced outage rate input, which essentially defines the percentage of time that a generating unit will likely be out of service in the future due to unexpected forced outages. Typically utility industry practice has been to develop expected forced outage rate assumptions by averaging historical forced outages over some period of time. It has been common practice for utilities to average four or five years of historical data. PacifiCorp uses four years worth of historical data. However, there is another aspect about PacifiCorp's methodology that is quite objectionable. Instead of using this data to compute average annual forced outage rates, PacifiCorp averages four years worth of monthly data to derive monthly projected forced outage rate assumptions.

Q. DO YOU AGREE WITH PACIFICORP'S PRACTICE OF USING MONTHLY FORCED OUTAGE RATES?

A. No I do not. I have been involved in preparing and reviewing power cost models used by many utilities since 1980. In my experience utilities simply do not model unplanned outage rates for generating units that reflect monthly variations.

There are three reasons why I think it would be far superior for PacifiCorp to use annual average forced outage rates in its production cost modeling, versus monthly average forced outage rates.

Q. CAN YOU PLEASE EXPLAIN THOSE THREE REASONS?

A. First, it is unreasonable to assume that forced outages, which are random events, can be predicted to occur more frequently in specific months. By contrast predicting that outages will occur randomly over a twelve month period is an entirely reasonable assumption. Modeling monthly forced outage rates adds absolutely no value to the accuracy of the results, and in fact, may call the results into question. Second, working with and evaluating monthly outage rates is much more time consuming than working with annual outage rates. This will be beneficial to all parties that continue to work with GRID. Finally, monthly outage rate modeling is a non-standard practice in the industry. PacifiCorp has provided no compelling evidence to prove why the use of monthly forced outage rates is reasonable. In response to CCS DR 21.11, the Company stated,

> *Monthly EFOR contributes to the process of normalizing power cost by recognizing that some months have a higher likelihood of outage than other months and outage costs differ by month.*

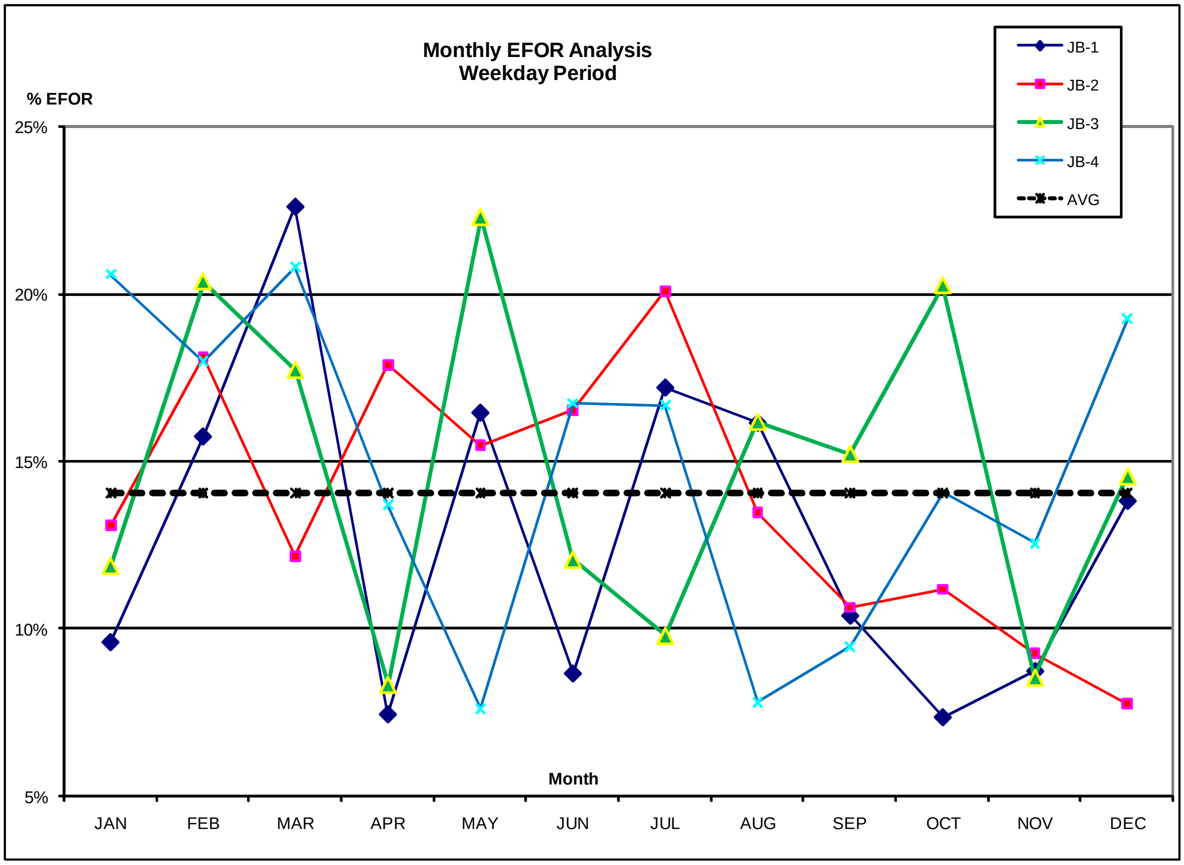
PacifiCorp has offered no evidence to support the contention that some months have a higher likelihood of outages occurring in those months compared to other months. In fact, a graph that I present below, shows that there is no basis to suggest that outages have a higher likelihood of occurring in one month versus another. I can think of only one case, involving Entergy, where that company briefly used monthly outage rates. However, as I recall, after parties objected to that practice in a FERC proceeding, Entergy modified its practice and has used annual forced outage rates ever since.

Q. WHY DON'T UTILITIES NORMALLY USE MONTHLY OUTAGE RATES?

A. Nothing can be readily identified related to any physical or engineering considerations that might explain why generating units would be more likely to fail during certain seasons or months, compared to others. Unless one can show that on a normalized basis a systematic pattern in unplanned outage rates exists, modeling of monthly outages is simply unrealistic, unnecessary, and antithetical to the normalization process.

Q. CAN YOU PROVIDE AN EXAMPLE OF THE MONTHLY VARIATION IN OUTAGE RATES THAT PACIFICORP HAS ASSUMED FOR ITS UNITS?

A. The following chart shows the monthly outage rates that the Company modeled in GRID for the Jim Bridger Units 1 - 4. The chart shows that there is no systematic difference in outage rates from one month to the next when any unit is compared to the others. Rather, the monthly variations tend to cancel each other out, and do not result in any systematic pattern.



I have used Jim Bridger because it is one of the Company's largest plants, and one of its most important resources, and it has four essentially identical units. If there was any systematic pattern in outages from one month to the next, it should show up in this chart. Instead the chart shows a fairly random pattern of outages. For example during January, which is a cold weather month, the graph shows below average outages for three of the Jim Bridger units, and above average outages for one. February shows just the opposite: above average outages for three units and below average for one. While May is the highest outage month for Unit 3, it is the lowest outage month for Unit 1. This chart shows that monthly variations in outage rates amount to little more than random fluctuations.

Q. DO YOU BELIEVE THE SAME RANDOM MONTHLY VARIATIONS IN FORCED OUTAGE RATES WOULD EXIST FOR OTHER PACIFICORP UNITS?

A. There is every reason to expect that this same random pattern of monthly outage rates would hold for all of PacifiCorp's generating units. Therefore, I recommend that the Commission require PacifiCorp to develop its estimates of NVPC using annual average forced outages instead of monthly average forced outage rates.

Q. DO YOU HAVE AN ADJUSTMENT BASED ON THE USE OF ANNUAL AVERAGE FORCED OUTAGE RATES VERSUS MONTHLY AVERAGE FORCED OUTAGE RATES?

A. Mr. Falkenberg also discusses this issue and he replaced the monthly average forced outage rates with annual average forced outage rates, and found that NVPC increased by a small amount. Mr. Falkenberg includes this adjustment as part of his Table 1.

IV. DERATION OF UNIT CAPACITY, HEAT RATE AND UNECONOMIC GENERATION ADJUSTMENT

Q. ARE YOU FAMILIAR WITH MR. FALKENBERG'S ADJUSTMENT TO DERATE THE MINIMUM CAPACITY OF GENERATING UNITS, AND TO MAKE AN ASSOCIATED HEAT RATE ADJUSTMENT?

A. Yes, I am. Mr. Falkenberg and I collaborated on the development of these adjustments.

Q. PLEASE BRIEFLY EXPLAIN THIS ISSUE.

A. One of the important considerations in production cost modeling is the treatment of generation forced outages, once the outage rates are entered into the production cost model. There are three common techniques used in production cost modeling to account for forced outages, including what's known as the convolution technique, the Monte Carlo method, and the deration method. In GRID, the deration method is used, which essentially reduces the amount of capacity of each generating unit by the expected forced outage rate. For example, assume that a 100 MW generating unit has an expected forced outage rate of 10%. In reality, this means it is expected that for 90% of the time the unit will operate at 100 MW, and for 10% of the time the unit will produce 0 MWs, as it is expected to fail during that period. The deration method multiplies the availability rate by the unit capacity and assumes the unit is available to operate for 100% of the time at that capacity, or something less than that capacity. Therefore, in the example above, the 100 MW unit would be derated by the availability rate and could be operated anywhere between 0 MW and 90 MW (100 * .9) for the entire time. In other words, the deration method would never allow the unit to operate above 90 MW.

Q. HAS PACIFICORP DESIGNED GRID PROPERLY TO USE THE DERATION METHOD?

A. Not exactly, we have discovered that GRID has a flaw in the way that it models capacity derations. We noticed this flaw based on our detailed scrutiny of hourly unit generation results. The problem is that not only should the maximum capacity be derated by the unit availability rate, but each of the other capacity segments, such as the minimum capacity segment, should also be derated by the unit availability rate. Based on my experience in instances when the deration method was applied, the entire unit capacity was adjusted using the forced outage rate. Mr. Falkenberg also discusses this issue in his testimony.

Similarly, an issue arises with regard to the heat rate curve used to account for the efficiency of the generating unit. Normally, each unit capacity point is associated with a unique point on the heat rate curve. When capacity segments are derated, an adjustment must be made to the heat rate curve so that the proper heat rate is still associated with the derated capacity. If an adjustment is made to derate the capacity of a generating unit, but no corresponding adjustment is made to the heat rate curve, then the wrong heat rate will be used for modeling purposes. Mr.

Falkenberg explains this issue in greater detail and presents an adjustment intended to correct the problem.

Q. BESIDES NOTICING THESE ISSUES IN THIS CASE, HAVE YOU ENCOUNTERED SIMILAR ISSUES WITH OTHER UTILITIES?

A. These sorts of adjustments have been commonplace in situations I've been involved with over the years. While working for a production cost model vendor, Energy Management Associates and its successor companies, similar situations at times arose. I have some recollection of times, in which some clients desired to scale the size of a generating unit to a smaller size, but still needed to have the same operating characteristics as the larger sized unit. For example, a client may have wanted to scale a 500 MW coal unit down to become a 250 MW coal unit. This may have been of interest in evaluating joint ownership of a new generating unit. To create the 250 MW unit, all capacity segments including the minimum capacity segment, had to be scaled by a factor of .5, not just the maximum capacity segment. Similarly, the heat rate curve had to be modified such that the efficiency when operating as a 250 MW unit would be the same as the efficiency when operating as a 500 MW unit. Scaling the unit in this fashion effectively requires the same process as derating the capacity of the unit to account for forced outage rate modeling. In fact, exactly the same results would be achieved if the company conducting the modeling exercise owned 90% of the unit and another company owned 10% of the unit. The same modeling technique used in adjusting the unit characteristics when scaling a unit should be used when modeling forced outage rates based on the deration approach.

Therefore, the technique proposed by Mr. Falkenberg is well accepted in the community of production cost modeling experts, and his adjustments to PacifiCorp's NVPC should be accepted by the Commission.

<u>Uneconomic Generation Issue</u>

Q. ARE YOU ALSO FAMILIAR WITH MR. FALKENBERG'S PROPOSAL TO ADJUST GRID TO REMOVE INSTANCES OF UNECONOMIC GENERATION FROM THE MODEL?

A. Yes I am. As in the case of the capacity segment deration and heat rate adjustment issues, we collaborated on this adjustment as well.

Q. IN YOUR EXPERIENCE, IS THERE ANY BASIS FOR ASSUMING IN A PRODUCTION COST MODEL THAT THE COMMITMENT AND DISPATCH SEQUENCE WILL NOT OPTIMIZE PROPERLY AND WILL LEAD TO A MORE COSTLY SOLUTION THAN NECESSARY?

A. I can't think of any reason, nor do I think that this is an acceptable outcome. The goal of the commitment and dispatch logic in a production cost model is to commit and dispatch the utility's generating unit in an optimal fashion subject to various constraints imposed on the process. These constraints include such considerations as must run requirements, operating reserve requirements, transmission limits, ramp rates, etc. The objective of the production cost model is to find the least cost solution possible, while satisfying these operating constraints. I have worked with a great number of models, and utilities over the years, and it is simply not acceptable when something other than the least cost solution to the unit commitment and dispatch process, subject to constraints, emerges from production cost models. Mr. Falkenberg believes that he has identified examples in the GRID model associated with the Company's filing in this case, in which all operating constraints are satisfied, yet GRID does not yield the least cost solution. In my experience, whenever these sorts of problems arise, it means that there is either a data input problem or a problem in the modeling logic. Once such problems are identified, production cost modeling experts go to great lengths to diagnose and solve the problem.

Q. WHAT DO YOU RECOMMEND REGARDING THIS ISSUE?

A. As discussed above, determining the least cost solution, subject to operating constraints is the required result from a production cost model according to the community of utility production cost modeling experts. Based on our analysis, the GRID model fails to meet this objective as required in the industry. For that reason, Mr. Falkenberg's proposed solutions should be adopted by the Commission. Furthermore, I recommend that the Company should endeavor to determine why the uneconomic behavior occurs, and then it should fix the problem or problems. As Mr. Falkenberg points out, the GRID manual itself states that the goal of utility production cost modeling is to achieve the least cost utilization of resources. Given that there are known problems that exist, the GRID model should be corrected before PacifiCorp's next General Rate Case, and Mr. Falkenberg's adjustments to work around these problems should be accepted by the Commission for this case.

V. BIOMASS NON-GENERATION AGREEMENT, SUNNYSIDE QF CONTRACT, AND SCHWENDIMAN QF CONTRACT

Biomass Non-Generation Agreement ("BIOMASS")

Q. PLEASE EXPLAIN THE BIOMASS NON-GENERATION AGREEMENT.

A. The Biomass contract is a very high cost QF contract, signed at a time when it was expected avoided costs would be much higher. As a result, the current contract price, $151/MWh, per the GRID output report, makes it one of the highest cost contracts on the system. For the past three years the Company has negotiated non-generation agreements with Biomass. Under this arrangement, for example, in 2007, Biomass produced no energy for a set period of time (April - June in 2007). In exchange Biomass was paid an amount that represented a discount from its standard contract rate.

The non-generation contract was beneficial for PacifiCorp because it got a larger discount from the QF than the cost to replace that power. It was apparently beneficial for Biomass because it avoided the need to purchase expensive fuel at times when replacement power was available at a lower cost in the market. In the end this amounted to a "win-win" situation that benefited both parties.

Q. SHOULD THIS ARRANGEMENT BE REFLECTED IN NORMALIZED RATES?

A. Yes it should. The Company has entered into such agreements for the past three years, and the circumstances underlying it appear likely to continue. As a result, I performed a GRID run based on the reasonable assumption that the terms and conditions would be identical to the 2007 agreement. The benefit of including the Biomass Non-Generation Agreement is about $0.5 million dollars on a total Company basis. Mr. Falkenberg has reflected this in his Table 1.

<u>Sunnyside Cogeneration QF Contract</u>

Q. PLEASE DISCUSS THE SUNNYSIDE QF CONTRACT?

A. The Sunnyside Cogeneraton Associates ("Sunnyside") QF Power Purchase Agreement (PPA) currently operates under the terms of the Third Contract Amendment. Sunnyside is a 30-year PPA that is set to expire in 2023, and is associated with a 45 MW base and an additional 8 MWs of purchase capacity. Since at least 2005, PacifiCorp has been working with Sunnyside to revise the Sunnyside PPA, which would result in implementing a Fourth Amendment to the Power Purchase Agreement. The current contract energy pricing has been based on a concept known as the realized marginal energy cost ("RMEC"), which has been a source of contention between PacifiCorp and Sunnyside for some time. Negotiations on the Fourth Amendment focused on replacing the RMEC method with another approach that would be more acceptable to the parties. The negotiation process has taken longer than expected due to the objections on the part of some of Sunnyside's bondholders.

At this time an agreement has been reached between the parties regarding the revised terms and conditions for the Fourth Amendment, and on March 18, 2008 a hearing was conducted by the Commission to consider PacifiCorp's request for approval of that Amendment (Docket No. 07-035-99). On April 3, 2008, the Commission issued its ruling approving the contract, and in its order, the Commission mentions that PacifiCorp has acknowledged that the Fourth Amendment will provide benefits to Utah's customers. (Commission Order, Page 6, Docket No. 07-035-99).

Q. HAS PACIFICORP INCLUDED THE IMPACT OF THE TERMS AND CONDITIONS OF THE FOURTH AMENDMENT IN THIS DOCKET?

A. No, it has not. PacifiCorp's GRID analysis in this docket modeled the Sunnyside contract under the terms and conditions of the Third Amendment, as there was no Commission order on the proposed Fourth Amendment at the time that PacifiCorp filed its request for a general rate increase in this proceeding.

Q. WHAT DO YOU RECOMMEND SHOULD BE DONE REGARDING THE SUNNYSIDE CONTRACT?

A. Since the Commission has now approved PacifiCorp's request in Docket No. 07-035-99, I recommend that the terms and conditions of the Fourth Amendment should be reflected in PacifiCorp's NVPC results associated with this case.

Q. HAS AN ANALYSIS BEEN CONDUCTED TO DETERMINE THE BENEFIT ASSOCIATED WITH THE FOURTH AMENDMENT?

A. Yes, one has. The Division of Public Utilities ("Division") requested that such an analysis be conducted in Data Request 2.1 in Docket No. 07-035-99. The Division's data request and the Company's response are as follows:

DPU Data Request 2.1

Please provide the detail of the costs in the current PacifiCorp general rate case (Docket No. 07-035-93) that have been included in PacifiCorp's revenue requirement request for the Sunnyside purchase power agreement. Please calculate and show with the same level of detail the costs that would be included in the revenue requirement request assuming the Fourth Amendment to the Sunnyside purchase power agreement is approved and in place for the entire test period (ending December 2008). Please summarize the system costs of the Sunnyside PPA both with and without the Fourth Amendment for the test period ending December 2008.

Response to DPU Data Request 2.1

Please refer to Attachment DPU 2.1 which provides the net power cost effect of the Fourth Amendment to the Sunnyside purchase power agreement (PPA). These calculations are preliminary numbers and are intended to give the DPU the estimated net power cost impact of the revised Sunnyside purchased power agreement. As illustrated in the attachment, the Fourth Amendment decreases the total cost of Sunnyside PPA by $3.6 million for the test period ending December 2008. Utah's allocated share is a $1.57 million reduction in revenue requirement.

Q. THE COMPANY MENTIONS THAT THESE RESULTS ARE PRELIMINARY. DO YOU KNOW WHY THIS MIGHT BE?

A. In response to the Committee's data request No. CCS 21.14, the Company stated that "The impact of the revised Sunnyside PPA agreement will not be final until the Fourth Amendment becomes effective." I assume that the Company believed, at the time it prepared the discovery response, that if the Commission were to approve the Fourth Amendment, then the $3.6 million benefit would be considered final on an annual basis. Now that the Commission has issued its order, it appears that the $3.6 million will be final when the Fourth Amendment becomes effective. My understanding is that the effective date will be back-dated prior to the beginning of the test period in this case, and will be in effect for the entire calendar year 2008 test period.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THE SUNNYSIDE CONTRACT?

A. I recommend that the terms and conditions of the Fourth Amendment should be reflected in the NVPC amount associated with this case. Therefore, I recommend that an adjustment be made to PacifiCorp's NVPC in the amount of $3.6 million on a total Company basis to reflect the impact of the new contract amendment. Mr. Falkenberg's Table 1 reflects a $3.6 million total Company adjustment based on the revised Sunnyside agreement.

Schwendiman QF Contract

Q. IS THERE AN ISSUE WITH THE SCHWENDIMAN QF CONTRACT?

A. There is a fairly minor issue with the Schwendiman QF contract in that the Company has set the wrong start date for the contract in the GRID input data. The Company provided copies of the Schwendiman QF contract and it appears that there are several amendments to the contract. It appears that the last revision of the contract is defined as the Third Amended contract and it is dated 10/17/2007, and the prior version was the Second Amended contract, which was dated 09/07/2007. The start of the QF contract in GRID appears to be consistent with the Second Amended contract which is May 1, 2008. However, the Third Amended contract, which is the more recent version, states that the start date will be November 1, 2008. I revised the start date of the contract in GRID and the NVPC costs were reduced by $164,307 on a system basis. These results are reflected in Mr. Falkenberg's Table 1.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.

Docket No. 07-035-93

Committee of Consumer Services Witness:
Philip Hayet

Exhibits CCS 5.1 and 5.2

April 7, 2008