Witness OCS 4D

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Service Rate in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations	)))))))	**Docket No. 09-035-23** **Direct Testimony of Randall J. Falkenberg On Behalf of the Utah Office of Consumer Services**

CONFIDENTIAL - SUBJECT TO PROTECTIVE ORDER IN DOCKET NO. 09-035-23

Public Version
Redacted Confidential Material Shaded in Gray

October 8, 2009

DIRECT TESTIMONY OF RANDALL J. FALKENBERG

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Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

A. I am a utility regulatory consultant and President of RFI Consulting, Inc. ("RFI"). I am appearing on behalf of the Office of Consumer Services ("the OCS".)

Q. WHAT CONSULTING SERVICES ARE PROVIDED BY RFI?

A. RFI provides consulting services related to electric utility system planning, energy cost recovery issues, revenue requirements, cost of service, and rate design.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS.

A. My qualifications and appearances are provided in Exhibit OCS 4.1.

INTRODUCTION AND SUMMARY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses PacifiCorp's ("the Company") Generation and Regulation Initiatives Decision ("GRID") model study of Net Power Costs ("NPC") for the test period ending June 30, 2010.

Q. PLEASE OUTLINE PACIFICORP'S NPC REQUEST IN THIS CASE.

A. PacifiCorp requests Total Company NPC of $999 million for the test year, resulting in an allocation of approximately $409 million to the Utah jurisdiction.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I have identified certain adjustments to the Company's GRID study shown on Table 1, below. Following Table 1 is an explanation of each adjustment.

Table 1
Summary of Recommended Adjustments - $

	Total Company	Est. Utah Jurisdiction
	SE	41.00%
	SG	41.13%
I. GRID (Net Variable Power Cost Issues)		
PacifiCorp Request NPC	999,143,849	409,681,359
A. GRID Market Caps		
1 GRID Market Caps	(10,983,676)	(4,510,509)
B. GRID Start Up Logic and Costs		
2 Correct Company Screens	(1,849,146)	(759,362)
3 Start Up Fuel Energy Value	(3,746,777)	(1,538,635)
C. Long Term Contracts		
4 SMUD Shaping	(526,689)	(216,288)
5 Biomass	(772,616)	(317,279)
D. Hydro Logic and Inputs		
6 Motoring and Efficiency Loss Modeling	(278,515)	(114,374)
7 Bear River Reserve Capability	(1,356,553)	(557,076)
E. Power Cost Modeling Issues		
8 Chehalis Start Costs	(433,460)	(178,003)
9 STF Transmission Test Year Synchronization	(4,132,606)	(1,697,078)
10 Transmission Imbalance	(714,685)	(293,489)
11 Cholla Capacity Upgrade	(311,838)	(128,058)
12 Wind Integration Error Correction	(1,202,561)	(493,838)
13 Wholesale Wind Integration Charges and Costs	(5,781,541)	(2,374,222)
F. Planned and Forced Outage Modeling Issues		
14 Planned Outage Schedule	(324,697)	(133,339)
15 Bridger Ramping	(279,185)	(114,649)
16 Minimum Loading Deration + Heat Rate Adj.	(2,752,818)	(1,130,460)
17 Currant Creek and Lake Side EFOR	(1,115,004)	(457,883)
18 Gadsby EFORd	(67,715)	(27,808)
Subtotal NPC Baseline Adjustments -	(36,630,082)	(15,042,350)
Allowed - Final GRID Result*	962,513,767	394,639,009

Recommended Adjustments

I recommend PacifiCorp's requested $999 million Total Company NPC be reduced by $36.6 million, lowering Utah allocated revenue requirements by $15.04 million.

A. GRID Market Caps

Adjustment 1 eliminates night time sales limits (called market caps) applied to the four major trading hubs. These market caps are based on a methodology approved in a 2003 Wyoming case. The circumstances originally supporting the adjustment, specifically use of

a historical test year and other factors are not applicable to the June 30, 2010 projected test year.

B. <u>GRID Start Up Costs and Commitment Logic Error</u>

<u>Adjustment 2</u> The Company proposes a "screening" methodology to address incorrect start and stop decisions of gas-fired generators modeled in GRID. The Company's proposed solution is flawed because it uses a <u>monthly</u> screen while actual scheduling decisions are made on a <u>daily</u> basis. Daily screens have been a part of the Commission approved correction for the GRID logic error since Docket 07-035-93. I recommend a solution that uses daily screens to better eliminate the error induced costs.

<u>Adjustment 3</u> includes the energy produced during the start sequence of gas units. This energy should accompany the start up fuel costs already included in GRID, which has been excluded by the Company.

C. <u>Long Term Contracts</u>

<u>Adjustment 4</u> implements the SMUD shaping methodology approved in Docket 07-035-93.

<u>Adjustment 5</u> adjusts Biomass generation to reflect an expected non-generation agreement. A Biomass non-generation adjustment was also approved in Docket No. 07-035-93.

D. <u>Hydro Logic and Inputs</u>

<u>Adjustment 6</u> corrects a double counting error in the modeling of hydro motoring and efficiency losses.

<u>Adjustment 7</u> corrects an understatement of the reserve carrying capability for the Bear River hydro resources.

E. <u>Power Cost Modeling Issues</u>

<u>Adjustment 8</u> reverses the unsupported revision of Chehalis start up costs that were used in Docket Nos. 08-035-35 and 08-035-93.

<u>Adjustment 9</u> synchronizes STF transmission costs, transfer limits and volumes. While the Company models STF transmission links in GRID based on 2005-2008 average energy volumes, it bases the cost on the much higher, 2008 levels.

<u>Adjustment 10</u> implements a transmission imbalance adjustment comparable to that approved by the Commission in Docket No. 07-035-93.

<u>Adjustment 11</u> properly reflects the Cholla capacity upgrade and transmission constraints limiting plant output.

<u>Adjustment 12</u> matches the east-west split for day and hour ahead wind integration costs with the correct test year values.

<u>Adjustment 13</u> reflects the final approved BPA wind integration rates and removes wind integration costs for wholesale (OATT) wheeling customers who do not pay for these services.

F. <u>Planned and Forced Outage Rate Issues</u>

<u>Adjustment 14</u> models a springtime outage for Currant Creek consistent with actual practice and the assumptions used in Docket No. 07-035-93.

<u>Adjustments 15</u> reverses Bridger ramping losses out of forced outage rates. The Company lacks the data necessary to compute these inputs.

<u>Adjustment 16</u> GRID fails to properly account for the impact of forced outages in the modeling of minimum capacity and heat rates. In Docket 07-035-93 the Commission requested further evidence concerning this adjustment.

<u>Adjustment 17</u> reduces new combined cycle plant unit outage rates to eliminate unreliable operation during their initial year of operation. The Company proposed this adjustment in Oregon Docket UE 207.

<u>Adjustment 18</u> applies the North America Electric Reliability Council ("NERC") $EFOR_d$ formula for peaking units. This is another adjustment proposed by the Company in Oregon Docket UE 207.

A. GRID MARKET CAPS

Adjustment 1: GRID Market Caps

Q. WHAT ARE MARKET CAPS?

A. Market caps are very powerful, though obscure inputs to GRID. These inputs control the assumed size[1/] of the hourly balancing energy market. If the market size is reduced NPC will almost invariably increase since profitable sales may not be made. Consequently, determination of the market size is one of the most important elements in determining test year NPC.

Q. IS THERE ANY EMPIRICAL WAY TO MEASURE THE MARKET SIZE?

A. Not to my knowledge. Electricity markets differ from traditional financial and commodity markets. Unlike shares of stock or barrels of oil, there is no fixed number of Megawatt Hours ("MWhs"). Electricity cannot be stored and the supply is price and time sensitive. Consequently, direct measurement of the size of the market is quite complex, and probably impossible. Lacking substantial justification for these assumed inputs, modeling of market caps is a-priori a questionable practice.

Q. HOW DOES THE COMPANY DETERMINE MARKET CAPS IN GRID?

A. The Company assumes that during most hours of the day and night the market size is confidential. This exceeds any amount of energy the Company is likely to ever have available for sale or need to purchase. However, during the "graveyard shift" (One to Five AM Pacific Standard Time) GRID inputs assume the market is

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[1/] In this context "size" should be taken to mean the amount of electric power which can be bought or sold before the market becomes illiquid – meaning that the price can no longer be reliably estimated by the forward price curve.

quite small, averaging only confidential.[2/] The graveyard shift market caps are not based on any real measurement of market size or liquidity. Instead they are computed as the amount of energy the Company sold into the balancing (or spot) market during the graveyard hours during a recent 12 month period.[3/] This is not a realistic measure of market size, because it assumes that sales were limited due to lack of market liquidity alone (essentially a lack of willing buyers). In reality, lack of supply, low prices, outages, derations, operating constraints or previous contractual commitments may have also influenced the volume of spot sales. In fact, the volume of balancing sales differs little between the graveyard shift hours and any other time. Consequently, there is no realistic basis for the graveyard shift market caps.

This calculation ignores the fact that the Company is making many other sales (for example, STF standard product sales) during the same hours. Because the vast majority of the Company's balancing is done with Short Term Firm ("STF") transactions, spot sales volumes are quite small in comparison. Because the Company considers only spot market sales, the market caps have no real relationship to the actual size of the market during the graveyard hours.

Q. HOW HAS THE COMPANY JUSTIFIED THE GRID MARKET CAPS?

A. Originally, the market caps were justified on the basis that they were needed to restrain coal-fired generation to realistic levels. The earliest reference I have

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2/ MDR 2.51 Confidential

3/ In this case, the 12 months ended December 31, 2008.

found regarding the issue was in the rebuttal testimony of PacifiCorp's former NPC witness, Mr. Mark Widmer, in a 2003 Wyoming general rate case:[4]

> Market caps are used to limit the size of the market during graveyard hours to a realistic size because the market is not completely liquid in the middle of the night. Without the caps, GRID would allow the coal units to generate more than they actually do.

Re Rocky Mountain Power, Wyoming Public Service Commission ("WPSC") Docket No. 20000-03-ER-198, Rebuttal Testimony of Mark Widmer at 24.

To my knowledge, this is the entire justification for the market caps. The GRID market caps and the methodology used to compute them have remained essentially unchanged since that 2003 Wyoming case.[5]

Q. HAS THE COMPANY'S MARKET CAP METHODOLOGY EVER BEEN APPROVED BY THE UTAH COMMISSION IN A CONTESTED CASE?

A. No. After the introduction of the market cap methodology, the only Utah proceeding where power cost issues were fully litigated was the 2007 case. In Docket No. 07-035-93, the issue was not contested. In the current Oregon case, Docket UE-207, Mr. Duvall testified that in implementing the market caps he continues to look to the reasoning of the order in the 2003 Wyoming case because it was the only case where a state commission has ruled on the matter.[6]

Q. ARE THE CIRCUMSTANCES OF THE 2003 WYOMING CASE STILL APPLICABLE TO THE TEST YEAR USED IN THIS CASE?

A. No, the test years differ substantially. Major differences include the GRID model logic itself, the type of test year used, the loads and resources of the system, the

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[4] I was also a witness in that case, and addressed power cost issues, including market caps.

[5] Note, however, the Company has introduced new markets, most notably Mona, and does not follow its methodology for computing market caps for that market. Rather the inputs for Mona are judgmentally determined.

[6] Oregon Public Utility Commission Docket No. UE – 207, Sur-Surebuttal Testimony of Gregory N. Duvall, PPL/111, page 10.

GRID topology, and the trading hubs modeled in GRID. Most importantly, the system has grown substantially since 2003, and a fresh look at the market caps is warranted. In fact, even Mr. Widmer recently testified[7/] that there is no longer any justification for the GRID market caps:

> **"Q. WHY DID PACIFICORP ADOPT THE MARKET CAP ADJUSTMENT?**
>
> **A.** Market caps were adopted to limit the size of the wholesale sales market during certain hours to what was thought to be a realistic size, because the market was not completely liquid in the middle of the night. Based on prior years' experience, PacifiCorp argued that without the caps at that time, GRID would allow coal units to generate more than they actually did because of excess generation available in the market.
>
> **Q. ARE MARKET CAPS STILL JUSTIFIED UNDER THE PREMISE THAT THE COAL UNITS WILL RUN TOO MUCH?**
>
> **A.** No. As PacifiCorp's system has grown so has the need for generation during all hours. As a result, PacifiCorp's low cost coal generation does not need to be artificially constrained in GRID because of an illiquid market. For example, actual coal generation during the deferral period was 45.9 million[8/] MWh and actual generation for the twelve month period ended March 31, 2008 was 46.3 million MWh . . . . Therefore, the market caps are no longer justified on the basis that the GRID model produces too much coal generation without the caps."

Re Rocky Mountain Power, WPSC Docket No. 20000-341-EP-09, Direct Testimony of Mark T. Widmer at 12.

Q. HAVE YOU COMPARED COAL GENERATION AT THE TIME WHEN MARKET CAPS WERE INTRODUCED TO CURRENT LEVELS?

7/ Mr. Widmer testified on behalf of Wyoming Industrial Energy Consumers in that case.

8/ In Wyoming the deferral period was the 12 months ended November 30, 2008. For the 12 months ended December 31, 2008, the actual coal generation was also 46.0 million MWh. As the market caps used by the Company are based on the 12 months ended December 31, 2008, this 12 month period provides a reasonable basis for comparison.

A. Yes. Table 2, below provides this comparison. It shows that there has been substantial growth on the system, eliminating the need for market caps in GRID.

Table 2
Coal Generation (MWH): Actual vs. GRID
12 Month Period Used to Compute Market Caps

	Wyoming 2003 Case	Utah 2009 Case	Change
Actual - Graveyard Shift	8,887,727	9,352,774	465,046
GRID - Graveyard Shift	8,865,319	8,793,567	(71,752)
Difference (GRID less actual)	(22,408)	(559,207)	
Actual - 12 Month Period	43,805,142	46,055,832	2,250,690
GRID - Test Year 12 Months	44,697,655	45,342,552	644,898
Difference (GRID less actual)	892,512	(713,280)	

Q. HOW MUCH COAL-FIRED GENERATION IS ASSUMED IN THE COMPANY'S FILED CASE?

A. Table 2 shows that for all hours, the Company's test year reports only 45.3 million MWh, as compared to actual generation of 46.1 million MWh for the 12 months ended December 31, 2008. However, a more significant measure of coal generation is the volume during graveyard shift hours. In the 2003 Wyoming case, actual coal generation during the graveyard hours was 8.89 million MWh for the historical period used to estimate the market caps (the 12 months ended May 31, 2003.) In this case, market caps were based on the 12 months ended December 31, 2008. Actual graveyard coal generation during that period was 9.35 million MWh, an increase of more than 465 thousand MWh. In contrast, the GRID output shows only 8.79 million MWh during the graveyard shift for the current test year. This is actually *less* than the coal generation from the 2003 Wyoming case referenced above (8.87 million MWh) and 559 thousand MWh *less* than the actual coal generation during the historical period used to estimate the market caps. If nothing else, this clearly demonstrates that the modeling of market caps in GRID must be revised. An obvious conundrum is that while market caps are justified on the basis of restraining coal generation during off peak hours, the determination of the market caps is completely unrelated to the amount of actual coal-fired generation.

Q. PLEASE DISCUSS OTHER DIFFERENCES BETWEEN THE 2003 WYOMING TEST YEAR AND THE TEST YEAR USED IN THIS CASE.

A. The 2003 Wyoming case used a normalized *historical* test year, as opposed to a *fully projected* future test year. There was also a very unique feature of the Wyoming test year in the 2003 case: all actual STF transactions were modeled in GRID.[9/] As a result, the volume of STF sales in the graveyard shift modeled in GRID, was equal to the actual test year volume: 3.75 million MWh. This is quite significant because there are two major types of transactions conducted at trading hubs: spot and STF (or standard product) trades. The size of the market is the sum of the spot and standard product markets. The Company considers only the size of the spot market, while ignoring the standard product market.

Limiting the market caps to the level of spot sales was accepted by the Wyoming Commission in the 2003 case. Otherwise GRID could have simulated transaction volumes in excess of actual levels, because the standard product market was already sized to the actual market level.

This is not the case for the projected future test year in this proceeding. For a projected future test year, STF transactions are limited to only those that the

9/ This was an adjustment to the test year that I recommended and the Company accepted.

Company had under contract prior to the filing date and balancing transactions make up the difference. Consequently, the volumes of STF transactions are substantially lower than those that occurred in prior periods, and which are likely to occur in the test year as it unfolds. This is especially true for sales during graveyard shift hours. Transactions volumes during those hours are far less in GRID than have occurred in recent times. Graveyard Shift sales in the GRID test year amount to only 1.8 million MWh. Even after removing the market caps from GRID, total graveyard shift STF and balancing sales amount to only 3.1 million MWh. Both figures are far below the amount included in the 2003 Wyoming test year (3.75 million MWh), as discussed above, and are also much less than recent actual results. Actual data shows that for the 12 months ended June 30, 2008 graveyard shift sales were 4.6 million MWh and even greater for the 12 months ended November, 2008.[10/] This is further evidence that growth in the system has eliminated any need for the market cap adjustment. Because of market caps, GRID substantially underestimates the volume of graveyard sales.

Q. PLEASE SUMMARIZE THIS POINT.

A. The Company's market cap methodology was first developed in a very unique 2003 Wyoming case that included all STF transactions in a historical test year. As such, it only considered spot sales to determine the market caps. The current, fully projected, test year includes only a fraction of the ultimate level of STF sales. As a result, the methodology used to calculate market caps in the 2003

[10/] Mr. Widmer reported more than 5 million MWh graveyard shift sales in his Wyoming testimony based on a 12 month ended November 30, 2008. I have confirmed his figures as well. (Direct Testimony of Mark T. Widmer, Wyoming Docket No. 20000-341-EP-09, Page 13.)

Wyoming case is invalid for a projected test year and results in an understatement of transactions volumes as well as coal generation during the graveyard hours.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Commission adopt Adjustment 1, eliminating the market caps for the four largest trading hubs: COB, Palo Verde, Four Corners and Mid Columbia. The impact of this adjustment is shown on Table 1. If this adjustment is adopted, graveyard shift sales will still be far less than actual recent results, and volumes of coal generation will also be reasonable as compared to results during the historical period, and about the same as the Company assumed in its 2008 General Rate Case ("GRC"). I also recommend the Commission require the Company to justify its judgmentally determined market caps for Mona in its next rate case.

B. GRID COMMITMENT LOGIC ERROR

Adjustment 2: Correct Improper Screens

Q. PLEASE PROVIDE SOME BACKGROUND CONCERNING THIS ISSUE.

A. In Docket 07-035-93, I demonstrated that GRID failed to make proper unit commitment (start up and shut down) decisions for gas units and certain call options. In Mr. Duvall's rebuttal testimony, the Company acknowledged this problem. The Commission adopted the "screening" adjustments I proposed to correct this GRID logic error. This adjustment simply overrides the logic in GRID and requires shut downs of specific gas units at specific times (usually at night.) As this was only an “interim solution”[11] it remained for subsequent cases to implement a better, more permanent solution. In Docket No. 08-035-38, the Company filed three different screening approaches to solve the problem in its July, December and March power cost studies. I proposed a different solution than the Company, building on the daily screening approach. In the end, the proper methodology was never decided because the 2008 case was settled without identifying specific adjustments.

Q. BRIEFLY DESCRIBE THE GRID LOGIC ERROR.

A. Absent user-supplied workarounds, called screens, GRID frequently fails to develop the least cost sequence of start-ups and shut-downs of gas-fired resources. The problem occurs because the logic in GRID separates the decision to commit resources from the operating constraints (mainly transmission constraints and market caps) imposed by other model inputs. However, these operating constraints are considered later in the determination of the economic dispatch of resources. The model incorrectly assumes that there is always a market for energy when making the start up or shut down decisions, but once the units are running, GRID recognizes there is no market for the energy these resources could otherwise produce due to the previously ignored constraints. The effect of this error is always to raise power costs. There is no way the problem could lower power costs because it always results in suboptimal resource utilization.

Q. WHAT KIND OF CONSTRAINTS ARE THE MOST SIGNIFICANT?

A. The most serious are market caps (discussed above) and transmission-related constraints. These constraints are significant because without liquid markets and

[11] Direct Testimony of Randall J. Falkenberg, Docket No. 07-035-93, page 6, page 29.

the free flow of energy across the transmission network, the Company cannot always sell surplus generation, purchase the lower cost energy, or dispatch units to their most efficient loading levels. In addition there are various operating constraints, including unit minimum loading levels, reserve requirements, minimum up and down times for generators. All of these interrelated factors are simulated in GRID. For example, if the Company has excess generation, but is unable to sell the energy due to market caps or transmission constraints, units are required to reduce output. In GRID, units are frequently dispatched at their minimum loading levels, which is typically their least efficient level of operation.

Q. HAS THE COMPANY ATTEMPTED TO ADDRESS THIS PROBLEM IN ITS CURRENT FILING?

A. Yes. The Company has again implemented a screening solution in GRID.

Q. HAS THE COMPANY APPLIED THE SAME SCREENING METHODOLOGY AS IN THE TWO PRIOR CASES?

A. No. In Docket No. 07-035-93, the Company acknowledged the GRID error and proposed to use a set of judgmentally determined annual screens to address the issue. Instead the Commission adopted the screens I proposed which were based on an analysis of hourly cost data. In Docket No. 08-035-38, the Company filed three different sets of screens. In its direct case (the July 2008 filing), the Company again modeled judgmentally determined annual screens. In the December second supplemental filing, the Company filed a new set of monthly screens based on a new methodology for combined cycle plants, along with some judgmentally determined annual screens for the peaking units. In the rebuttal phase (the March 2009 filing) the Company changed its methodology again, for the first time reflecting start up costs in the determination of the monthly screens for combined cycle plants. In the instant case, the Company has now changed its method again building on the monthly method from the prior case, but expanding it to include peaking units and their start up costs on a monthly basis. However, the Company also retains the unsupported annual screen for peaking units in addition to the latest monthly screens it is using.

Q. ARE YOU OBJECTING TO THE COMPANY CHANGING ITS SCREENS AND THE UNDERLYING METHODOLOGY?

A. No, I am merely recounting this history to demonstrate that the Company has tried a variety of methods to address the problem.[12/] I believe it is completely appropriate to seek the best solution possible, even if that results in changing methods from time to time. However, at times, the Company has objected to implementation of more rigorous solutions.[13/] Because the issue is quite complex, a permanent solution is going to be difficult to achieve. It is important to recognize that, as discussed above, the problem can only serve to *increase* power costs. Therefore, the Commission should insist that the best solution possible be implemented. Otherwise, the Company will have no incentive to correct the error inside of GRID because it can only benefit from any uncorrected error induced costs. While the new screening methodology is an improvement over the methods used in the Company's various 2008 filings, it falls short of the goal of eliminating uneconomic generation in GRID and introduces some new problems.

12/ In fact, the problem and its various solutions seems to date back to the 2003 Wyoming case discussed in reference to market caps, as that case also included adjustments to correct incorrect operation of gas-fired resources. I think this demonstrates the Company has made little progress concerning this issue. Wyoming Public Service Commission Docket No. 20000-ER-03-198, Final Order, page 19, paragraphs 48a and 48b.

13 Rebuttal testimony of Gregory N. Duvall, Utah Docket No. 08-035-38, page 42, line 952. Sur-surebuttal testimony of Gregory N. Duvall, Oregon Docket No. UE – 207, PPL/111, page 2.

Q. PLEASE ELABORATE.

A. The screening method used by the Company is based on a *monthly average* rather than daily analysis. Consequently, it fails to identify the specific days when the cycling units should or should not be running and also fails to determine the best start up and shut down times for each day. In real time operations, the decision to start up, or shut down a cycling unit is made on a *daily rather than a monthly basis*. As a result, the Company's proposed screens don't eliminate all of the error induced costs in GRID.

Q. WAS GRID INTENDED TO BE A MONTHLY MODEL?

A. No. In fact, the Company replaced its prior monthly energy models with GRID in order to implement an hourly model. Therefore, imposing a monthly solution on the model is illogical, and inconsistent with most of the other inputs used in GRID. For example, loads, market prices, planned outages, short-term and long term contracts all vary on a daily and even hourly basis in GRID. The intention has always been that GRID should simulate actual practice, which is a daily decision process that seeks to start up and shut down each cycling plant in the least cost manner by determining the best operational decisions for each day, and hour of the year. The logic built into GRID already attempts to make the right commitment decisions on a *daily (even hourly)* basis.

Q. EXPLAIN THE PROBLEMS RESULTING FROM THE USE OF MONTHLY SCREENS.

A. The Company only considers whether, on average, the same start up and shut down sequence should be used for an entire month. If so, then the plants are shut down every single night of the month at the same time and then allowed to restart the next day at the same time, irrespective of market prices, loads or start costs, or other resources for any particular day.

This can cause several additional problems. First, the monthly method picks the screen that is best “on average” during the month ignoring differences in costs between different days of the week, or month. The monthly average screen may allow a unit to run every night during the month, even though there are many nights when it shouldn’t. For example, there may be times when it is better to shut down units on weekends or holidays, rather than allow them to run every day as dictated by the monthly screens. Because market prices are typically lower on weekends, it may often be the case that a weekend shutdown is economical, but not during weekdays. Second, units may actually be *required* to shut down by the Company’s screens at times when they should have been allowed to run. This could happen if there are specific nights within a month where not operating the units produces a large benefit, even if there are other nights during that month when they should be running. Third, the monthly screen may allow a unit to run on days when it otherwise should not be running at all. Finally, the Company does no rigorous analysis of the days or hours when the specific units should be prevented from running. While a 12 midnight shutdown may be appropriate one night, the very next night might call for a different shutdown period.

In real time operations, all of these outcomes are considered as the operators attempt to devise the least cost start and stop sequences for cycling units each *day and hour* of the year. As noted above, GRID was designed to develop this solution on a daily (and even hourly) basis as well and the current logic attempts to simulate these very decisions.

Q. HAS THE COMPANY INDICATED ITS POSITION REGARDING THE USE OF A DAILY SCREENING METHOD?

A. Yes. Based on testimony filed in the 2008 GRC and even more recent cases in other states, it appears they object to using a daily screening method. In the 2008 case, Mr. Duvall argued that use of daily, rather than monthly, screens did not add significant new capabilities and that it required more effort to develop daily screens. Mr. Duvall has suggested at various points that the use of monthly not daily screens were accepted by the Commission in Docket 07-035-93. Finally, Mr. Duvall has also suggested that it is not appropriate to change methodologies related to the screening solution from case to case.

Q. DO YOU AGREE THAT DAILY SCREENS DO NOT ADD NEW CAPABILITIES?

A. No. Exhibit OC2 4.2 shows that the amount of error induced costs removed from GRID is significantly higher based on use of a daily, rather than a monthly, screening method. In fact, the daily screening method eliminates almost five times as much of the error induced costs. These analyses are based on the Company's own runs that were used to develop the screens and illustrates that the Company's monthly analysis simply fails to remove all of the error induced costs.

Q. PLEASE ADDRESS THE CONTENTION THAT IN DOCKET 07-035-93 THE COMMISSION ACCEPTED MONTHLY RATHER THAN DAILY SCREENS.

A. On page 28 of the final order in Docket 07-035-93, the Commission accepted my proposed adjustments to correct the logic error, which included daily screens. Daily, not monthly screens have been a part of the solution to this problem since

Docket 07-035-93[14/] and even the approach approved in that case was described as only an interim solution in my testimony.[15/]

Exhibit CCS 4.5 from the 2007 case showed a daily screening analysis for West Valley and the inputs for the West Valley adjustment used the results of those daily screens. The workpapers and exhibits I filed in that case also used a daily screening approach. Further, even in some cases where the daily screening wasn't applied rigorously, I analyzed the potential daily screen impacts in my workpapers.

Q. DOES IT REQUIRE ANY MORE EFFORT TO IMPLEMENT A DAILY RATHER THAN MONTHLY SCREEN?

A. No. Nearly all of the work in developing the screens consists of performing multiple GRID runs, and combining the hourly cost data into a single spreadsheet. This work is the same in the Company's method as in the OCS method. The subsequent analysis is simply to copy the hourly cost data into a spreadsheet which automatically generates the GRID input records. It takes no more time or effort to do the correct analysis than the Company's less rigorous approach. The only difference is that a different spreadsheet is being used in the final step.

Q. ARE THE OPTIMAL SCREENS INFLUENCED BY MARKET PRICES AND OTHER INPUT CHANGES?

A. Yes. The screens are influenced by adjustments that may be accepted by the Commission, most notably the market caps and forward prices. Consequently, the Company should be required to re-determine if the final adjustments differ significantly from the ones I propose. If the Commission does not require this

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[14/] Direct Testimony of Randall J. Falkenberg, Docket No. 07-035-93, page 29ff.

[15/] *Id.*

additional step, it could be allowing the Company to benefit from the errors built into the GRID model at the expense of customers. This will likely lessen any incentive the Company has to ever correct this problem.

Q. EXPLAIN ADJUSTMENT 2 ON TABLE 1.

A. This presents the results of all screen related adjustments, including new screens for Currant Creek, Lake Side, Gadbsy and purely financial screening adjustments for the duct firing resources. Because of the complexity of this problem, it may still be possible to develop better screens. However, the screens I propose do a significantly better job of reducing the error induced costs than those proposed by the Company. As in prior cases, this is only an interim solution to be used, and if possible improved upon until the GRID logic error itself can be fixed.

Q. ASSUMING A SOLUTION TO THE GRID LOGIC ERROR CANNOT BE IMPLEMENTED BY THE NEXT CASE DO YOU HAVE ANY OTHER RECOMMENDATIONS?

A. Yes. I recommend the Commission require the Company to implement a minor GRID modification to export the hourly sum of fuel and purchase power costs less sales revenue. This would facilitate the production of screens allowing a time savings for all parties and should be required to be included in the very next power cost related case.

<u>Adjustment 3: Start Up Fuel Energy Value</u>

Q. SHOULD START UP GAS COSTS BE INCLUDED IN GRID?

A. Yes, I first recommended this in Docket 07-035-93. These costs may be considered as part of NPC as they are included in FERC Account 547. However, the Company considers only the cost of fuel required to take the unit from a warm shut-down state to minimum load while ignoring the energy being produced during the start sequence. The confidential figure below shows the energy generated during the Lake Side start sequence and how I propose to model this energy in GRID.

Confidential Figure 1

This figure shows the instantaneous output of Lake Side during a startup sequence lasting approximately 100 minutes as well as the proposed GRID inputs. It shows that there are only a few minutes when the plant output is negative (i.e., drawing energy from the grid). The remaining time during the start sequence, the output is positive. For the first forty minutes, the average output is about confidential, for the last hour, the average output is approximately confidential. Over this entire period, the resource generates confidential.[16/] Because the Company is already including the fuel cost associated with this generation in GRID, it is appropriate to include additional energy as well. Similar data was available from discovery for Currant Creek. For Chehalis, comparable start up energy was not available, so I developed the required inputs from hourly logs.

Q. WHY DOESN'T THE COMPANY INCLUDE THIS ENERGY IN GRID?

A. The Company has made various arguments related to this point. However, these arguments all go to the proper level of the adjustment, not to the appropriateness of including the start up energy. The Company has argued the start up energy has little value. No matter what, the value of the energy (whether large or small, positive or negative) should be included in GRID. The Company's approach is only correct in the highly unlikely situation that the start up energy has a value exactly equal to zero for every gas unit, every time they start.

Q. DID YOU CONSIDER THE RESERVE REQUIREMENTS IMPOSED BY THE START UP ENERGY IN GRID?

A. Yes. This was one of the Company's arguments against modeling the start up energy in GRID and is discussed Mr. Duvall's direct testimony. However, I did model the reserve requirements associated with the energy generated during the start up sequence. Based on my GRID runs the impact is rather small.

Q. DID YOU RECOGNIZE THAT DURING THE INITIAL START SEQUENCE, THE COMBINED CYCLE PLANTS DRAW ENERGY FROM THE GRID?

[16/] Confidential.

A. Yes. The Company has suggested that because the start sequence initially uses some energy from the grid, none of it should be counted.[17/] However, the time when the resources draw energy from the grid is only during the first few minutes of the start sequence. This energy produced during starts has to go somewhere, and I think the only rational assumption to make is that it goes into the power system, offsetting purchases, or other generation. GRID reflects a reduction in coal generation and other resources to account for this energy. If GRID is realistic enough to model power costs for purposes of setting rates for customers, it should also be considered valid for modeling start up energy as well.

Q. IS IT STANDARD INDUSTRY PRACTICE FOR UTILITIES TO MODEL START UP ENERGY IF THEY ARE ALSO MODELING START UP FUEL COSTS?

A. Yes. Industry standard chronological power cost models such as PROMOD and PGE's MONET model also reflect the energy produced during the start up sequence. PacifiCorp's approach is an "outlier" and should not be accepted by the Commission.

Q. DO PACIFICORP DOCUMENTS REVEAL THAT THE COMPANY HAS ASSUMED THIS START UP ENERGY HAS VALUE?

A. Yes. In Docket 07-035-93 data request CCS 7.16 sought information concerning the computation of the start up costs used in GRID. In its response, the Company provided the following (public record) document, Attachment 7.16b. An excerpt is shown below:[18/]

17/ Rebuttal Testimony of Gregory N. Duvall, Docket No. 08-035-38, page 43.

18/ The portion of the document that is not shown merely presents the same type of data for a hot start and a cold start, which also ascribe value to start up energy in the same manner as the portion of the document which is shown here.

PacifiCorp

Estimated Startup Fuel Consumption and Power Production

Assuming:				
Site conditions=ISO				
Evaporative Cooling Tower				
Fuel Cost ($/MM BTU (HHV))=	$5.00	0.034299	0.0336108	
Power Sale Price ($/kWh)	$0.050			
Configuration		2xS107FA SS	1xS207FA	
Net Plant Output (kW)		519,468	530,299	
Net Plant Heat Rate (BTU/kWh (LHV))		6,180	6,056	
Plant Heat Consumption (BTU/hr (LHV))		3,210,312,240	3,211,490,744	3,568 mmBtu/start
GT Output (kW)		343,192	343,192	
ST Output (kW)		187,576	198,299	
Gross Power (kW)		530,768	541,491	
		0.97871	0.97933	
Warm Start				
Starting Time (minutes)		109	122	
Fuel Consumption/start (BTU/hr (LHV))		1,701,465,487	2,135,641,345	2,373 mmBtu/start
Fuel Cost/start ($)		$9,443	$11,853	
Power Produced/start (kWh)		256,126	262,603	
Power Value/start ($)		$12,806	$13,130	
Start up Cost ($)		-$3,363	-$1,277	

The document clearly shows that the Company believed the combined cycle plants would produce energy with substantial value in the past, more in fact than the amounts I have modeled in GRID. However, since that time, the Company testimony has contended that the start up energy has no value and the Company has refused to provide an update to that document.[19/]

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission accept Adjustment 3 to reflect the value of start up energy in GRID.

[19/] See Response to CCS 18.51, Docket No. 08-035-38.

C. LONG TERM CONTRACT ADJUSTMENTS

Q. DOES GRID MODEL PURCHASE AND SALES CONTRACTS?

A. Yes. GRID includes the costs and energy produced by its long-term and short-term contracts. I will discuss issues related to two long-term contracts where the Company failed to implement Commission approved adjustments.

<u>Adjustment 4: SMUD Contract Shaping</u>

Q. WHAT IS A CALL OPTION CONTRACT?

A. These contracts allow a counterparty to schedule energy deliveries as desired, subject to specific limitations. The Company models "call option sales" for the Sacramento Municipal Utility District ("SMUD") and several other counterparties. The SMUD contract has an annual energy limit of approximately 350,400 MWh (and a 100 MW maximum hourly take). The GRID modeling assumes SMUD will take its entitlement during the highest cost[20/] 3504 hours[21/] of the year.

Q. IS THE GRID MODELING REALISTIC?

A. No. Based on actual data, SMUD uses its entitlement in a manner that is less costly than assumed in GRID.

Q. CAN YOU EXPLAIN WHY SMUD DOESN'T USE ITS ENTITLEMENT AS ASSUMED IN GRID?

A. There are many reasons why SMUD may not utilize the contract in the very costly manner assumed by the Company. Differences in forward price curve assumptions, transmission constraints, availability of the SMUD's own generation

20/ Based on COB market prices.
21/ 350,400/100= 3504.

and other unknowns drive its decisions to use the available energy. In the end, SMUD is interested in serving its own customers at the least possible cost (subject to its own constraints), not in maximizing the cost to PacifiCorp. The Company's approach does not represent "normalization" of the contract, but rather the most costly outcome possible. I recommend an adjustment to shape monthly energy deliveries to SMUD based on actual data rather than in the highest possible cost method as assumed in GRID.

Q. IN DOCKET NO. 07-035-93, YOU PROPOSED THE SAME NORMALIZATION ADJUSTMENT FOR SMUD. DID THE COMMISSION DECIDE THE ISSUE IN ITS ORDER?

A. Yes. The Commission approved the adjustment and later reaffirmed it by not granting the Company's request for reconsideration of the matter.

Q. DID THE COMPANY IMPLEMENT THIS COMMISSION APPROVED ADJUSTMENT IN THIS CASE?

A. No. The Company has made a number of different arguments in its opposition to the adjustment. For example, Mr. Duvall has suggested that if it were correct to use the actual data in determining the dispatch of call option sales contracts, one should assume the Company should do the same for purchase agreements such as the Hermiston purchase or the Bonneville Power Administration ("BPA") contract.[22/]

Q. DO YOU AGREE WITH THESE ARGUMENTS?

A. No. Unlike the case of the SMUD contract, the Company (not the counterparty) decides when to use, or not to use these resources and does so in order to minimize costs, subject to the applicable constraints. In the case of SMUD, the

22/ Rebuttal Testimony of Gregory N. Duvall, Docket No. 08-035-38, page 19ff.

Company simply does not know and has not modeled any of the constraints, requirements or forward price curves used by the counterparty. Absent such information, the shaping adjustment for SMUD is a proxy for the many unknown factors driving the counterparties' use of its entitlement. In contrast, the forward curves and constraints PacifiCorp faces are known and modeled in GRID.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission continue to normalize the SMUD delivery pattern by accepting Adjustment 5. This will implement a more realistic monthly energy distribution for the SMUD contract than the Company proposal.

<u>Adjustment 5: Biomass Contract</u>

Q. HAS THE COMPANY MODELED A NON-GENERATION AGREEMENT WITH THE BIOMASS PROJECT?

A. No. This adjustment was also approved by the Commission in Docket No. 07-035-93. Mr. Hayet further explains the basis for Adjustment 5 which implements a comparable adjustment for the current test year.

D. HYDRO MODELING

<u>Adjustment 6: Hydro Modeling</u>

Q. HAS THE COMPANY CHANGED THE HYDRO MODELING IN GRID?

A. Yes. The Company now uses the VISTA model to develop hourly hydro inputs for GRID. In the past, the VISTA model was used to develop weekly hydro energy values, which were then shaped within GRID to meet hourly demands and maximize value while reflecting reserve requirements and applicable constraints.

Q. DO YOU HAVE ANY CONCERNS REGARDING THIS MODELING CHANGE?

A. While VISTA appears to be an industry standard model enjoying some acceptance elsewhere, I do have some concerns. First, I asked the Company to provide GRID input data based on current test year assumptions, but using the prior modeling technique, but it didn't provide it.[23/] My estimate of the impact of this modeling change indicates the new methodology increases power costs by approximately $3 million on a Total Company basis, in addition to the $2 million increase related to the Company's new "Efficiency Losses" and "Motoring" adjustments. This is surprising because the logic built into GRID uses a hydro peak-shaving algorithm, rather than the price shaping technique applied in VISTA. In theory, price shaping should produce a more optimal dispatch, though different modeling of various constraints could explain these differences. Another concern is that the reserve allocations from the new methodology appear less realistic than those resulting from the previous GRID logic. Also, while VISTA is an accepted model, it is quite opaque, and may not be available to parties. Finally, the Company conceded in discovery responses OCS 9.3-9.7 that there were errors in its computation of the efficiency loss and motoring adjustments, principally double counting the later.

Q. WHAT IS YOUR RECOMMENDATION?

A. For purposes of this case, I recommend only correcting the errors in the motoring and efficiency loss adjustments. This is Adjustment 6 on Table 1. I also recommend that if the Company wishes to use the VISTA hourly modeling in

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23/ The Company stated in responses OCS 9.1-9.2 that it had not prepared such an analysis, and therefore, wouldn't provide one future cases it be required to provide a direct comparison to the prior (weekly peak shave) modeling method used in GRID, provide parties the comparable GRID inputs, and justify the changes in reserve allocations, hydro dispatch and the ultimate NPC impacts.

Adjustment 7: Bear River Reserve Carrying Capability

Q. ARE THERE OTHER HYDRO INPUTS THAT REQUIRE REVISION?

A. Yes. The Bear River resources (Oneida and Cutler) have a limited amount of storage capability. In GRID, it is assumed that the storage capacity provides up to 30 MW of reserve carrying capability. However, review of actual reserve allocation data shows that these resources frequently carry reserves of 50 MW or more. As a result, I recommend an increase to the reserve carrying capability. I used confidential based on the average of the maximum monthly reserve allocations from November 2006 to present (the period of time where accurate data was available.) Actual reserve allocations exceeded this level for hundreds of hours.

E. POWER COST MODELING ISSUES

Adjustment 8: Chehalis Start Up Costs

Q. HAS THE COMPANY CHANGED THE START UP COST ASSUMPTIONS FOR CHEHALIS?

A. Yes. The Company now assumes an O&M cost of confidential per start and fuel requirement of confidential MMBTU per start. This is a substantial increase over the values of confidential per start and confidential per start used previously.

Q. DOES THE OCS AGREE WITH THE NEW START UP COST AND START UP FUEL INPUTS ASSUMED FOR CHEHALIS?

A. No. These inputs differ from those assumed by the Company in Dockets 08-035-38 (the 2008 GRC) and 08-035-93 (Chehalis approval). Because the Company has no documentation supporting these new assumptions, the prior (IRP based) inputs should be used. The only support the Company has provided for the new inputs is that they are similar to those used for Currant Creek. However, the start up energy for Chehalis appears substantially overstated relative to Currant Creek values. The Commission should not accept unjustified and undocumented assumptions.

Adjustment 9: STF Transmission Test Year Synchronization

Q. PLEASE DISCUSS THE MODELING OF NON-FIRM AND STF TRANSMISSION IN GRID.

A. In Docket No. 08-035-38, the Company began including non-firm (NF) transmission capacity in GRID, based on 48 months of history.[24/] In that case, I recommended STF transmission be included as well. The Company agreed to do so in its rebuttal testimony, again based on 48 months of history, though they didn't adopt the specific STF transmission modeling I proposed. In the instant case, the Company also included STF transmission links as well as non-firm transmission links. However, the Company now expresses concern about the inclusion of non-firm transmission links in GRID, though as stated above, it continues to model it.

24/ This was required by the final order in Docket No. 07-035-93.

Q. SHOULD NON-FIRM TRANSMISSION BE RECOGNIZED IN GRID?

A. Yes. I continue to recommend that non-firm transmission be included in GRID. These are available resources and are being used regularly by the Company. The Company has provided no substantive basis for overturning the Commission's decision to include non-firm transmission in Docket 07-035-93.

Q. DO YOU AGREE WITH THE COMPANY'S MODELING OF STF TRANSMISSION?

A. No. The Company developed STF transfer limits based on four year average energy flows. I believe that use of the most recent single year data for non-firm and STF transmission is more consistent with the way in which all other transmission costs and resources are modeled in GRID, and would better reflect current conditions. However, the Company has already included STF transmission based on a four year average energy flows, and has recently objected rather strenuously to use of a single recent year. I believe that use of a single or multi-year average is probably not as critical as having consistency between the capacity, energy flows and costs of the STF transmission links modeled. If four year averages are used to determine the STF and NF transmission links, then comparable data should be used to determine the costs. The Company has not done so, but instead pairs the higher 2008 costs for STF transmission with lower four year average (2005-2008) energy transfers.

Q. HOW DOES THE COMPANY JUSTIFY THIS APPARENT MISMATCH?

A. Mr. Duvall stated previously **"***This normalizing methodology is identical to using a four-year average availability for the generating resource, but most recent fuel costs for the expenses of the generation***."**[25/]

Q. DO YOU AGREE?

A. No. This analogy is flawed because it ignores cause and effect. The physical transfer capacity and transaction volumes of the links modeled in GRID change substantially from year to year, and as a result, the associated costs will change. In this case, cost drives capacity – the more the Company pays, the more transfer capacity it can buy. In the generator example, the cost of fuel does not determine the capacity of a generator, or influence outage rates. An increase in gas prices doesn't increase the size of Currant Creek, or result in more outages.

Q. COULD YOU PROVIDE AN EXAMPLE THAT IS ANALAGOUS TO THE COMPANY'S METHOD?

A. Yes. An example of the Company method would be the case of a power plant expanded from 200 MW to 400 MW in the middle of a four year period. The Company's approach would be to pair the fourth year fuel costs (for the now 400 MW plant) with a much lower four year average capacity (300 MW.) This is clearly inconsistent.

Q. DO YOU HAVE DATA SHOWING THIS MISMATCH EXISTS IN GRID?

A. Yes. The figure below illustrates the mismatch resulting from the Company's methodology. The costs and volumes of STF transmission have increased substantially in recent years. The Company uses four year average (2005-2008) transfer volumes to determine the STF capacity inputs though GRID doesn't fully

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[25/] Oregon Public Utility Commission Docket No. UE 207, Rebuttal Testimony of Gregory N. Duvall, PPL/111, page 39 utilize that capacity. In the Company's test year, transfers are only 1,124 thousand MWh, or about 82% of the four year average volumes. However, the Company is including transaction related costs of at least confidential million based on the 12 months ended December 31, 2008. This is conf% of the four year average cost. This results in an average transfer cost per MWh of confidential/MWh, or more than twice the four year average transfer cost of confidential/MWh. The 2008 actual costs, for example, were conf million supporting transfers of conf million MWh, for an average cost of $conf/MWh.

Figure 2 Confidential

To address this issue, I have identified the transaction related costs and modeled the cost of transfers based on volumes, the same as non-firm transmission modeled by the Company. I would note that Mr. Duvall stated STF and non-firm transmission modeling should be modeled on the same basis in Docket No. 08-035-38 and represented that he had done so.[26/] This approach models both non-firm and STF transmission in an identical manner.

Adjustment 10: Transmission Imbalance

Q. WHY SHOULD TRANSMISSION IMBALANCE CHARGES AND FEES BE REFLECTED IN THE TEST YEAR?

A. Test year NPC should reflect the net normalized value of transmission imbalance charges and fees the Company collects from or pays to third parties because these are routine, recurring events. These imbalances are treated as STF energy transactions in the actual cost reports the Company frequently cites as a reliable power cost benchmark, and should also be reflected in GRID as well. This is another adjustment approved by the Commission in Docket 07-035-93 excluded by the Company in this case.

The Company charges third party transmission customers when their load-resource balances differ from scheduled amounts. Likewise, the Company pays such fees when it is out of balance on a third party transmission provider's system. Typically, the imbalance charges are discounted below or marked up above the market price depending on whether the imbalance results in a purchase or sale. Because the Company is out of balance less often than its transmission

[26/] "The Company agrees that the modeling of non-firm transmission and the modeling of short-term transmission are closely related. For this reason, the Company is willing to adjust its filing in this case to model short-term firm transmission on the same basis as it models non-firm transmission." Rebuttal Testimony of Gregory N. Duvall, Docket No. 08-035-38, page 35, line 793.

service customers, imbalances are a below market source of energy for the Company. Exhibit OCS 4.3 contains various data responses explaining this issue in more detail. I quantified this adjustment based on data for the 48 months ended December 31, 2008 consistent with the modeling of other types of adjustments modeled in GRID.

Q. HOW DID YOU COMPUTE THIS ADJUSTMENT?

A. Transmission imbalance is priced at a premium or discount to the market price. Since the Company has to acquire or dispose of the imbalance energy at market, the ultimate effect is financial. The Company benefits whether there is a positive or negative imbalance. As a result, I modeled this adjustment as a purely financial adjustment. However, I modified this adjustment from the method used in Docket 07-035-93 in order to reflect some of the valid criticisms the Company has made in the past. The most significant change was to eliminate the transmission imbalances due to OATT customers, as those charges are not retained by the Company. I also use a 5% discount or markup rather than 10% as I assumed previously. These modifications have reduced the value of the adjustment.

<u>Adjustment 11: Cholla Capacity Rating</u>

Q. HAS THE COMPANY REFLECTED THE CURRENT CAPACITY RATING FOR CHOLLA UNIT 4?

A. No. The Company recently upgraded the capacity of Cholla Unit 4 from conf to conf MW. In GRID, the Company reflects only confidential based on the Company's Firm Transmission Right ("FTR") capacity limit. However, the conf MW transmission limit seldom has any effect because the Cholla plant capacity is already derated for other reasons below the FTR capacity. In fact, Cholla suffers numerous capacity derations that are already reflected in the GRID input outage rates. Based on my review of outages and generator logs, these derations moot the transmission capacity limit around 80% of the time. Because these derates are already counted in the forced outage rate modeling, the artificial limit on Cholla's capacity is a "double count." Further, STF and non-firm transmission allow some additional transfer capacity for Cholla.

A better way to address this problem is to treat the transmission limit as a capacity deration that applies only when the unit is otherwise fully available. Even with the 10 MW upgrade, Cholla would be available to operate at more than conf MW only 20% of the time. The remaining 80% of the time, the transmission limit is irrelevant. As a result, I have made an adjustment to the Cholla capacity to reflect the expected value of the transmission related derations[27/] as a deduction from Cholla's maximum capacity. Consequently, I model Cholla capacity at confidential MW, rather than confidential MW.

Adjustment 12: Wind Integration Error Correction

Q. EXPLAIN THIS ADJUSTMENT.

A. Mr. Hayet addresses this issue in more detail. The Company has computed its hour and day ahead wind integration costs on a control area basis. However, the Company didn't use the actual test year wind energy weights for the control areas to compute this cost. This adjustment corrects that problem.

27/ Confidential

<u>Adjustment 13: Wholesale Wind Integration Charges and Costs</u>

Q. PLEASE DESCRIBE THIS ADJUSTMENT.

A. Mr. Hayet testifies that this adjustment reflects a reduction to BPA's requested wind integration charges occurring as a result of the final decision in BPA's most recent transmission rate case.

The adjustment also removes wind integration costs for OATT customers that are not paying for wind integration service. The Company has included costs related to providing wind integration services to third party wind farms located in Washington (the Stateline project) and Wyoming (the Long Hollow wind farm). PacifiCorp provides transmission services to these customers under its Open Access Transmission Tariff ("OATT"), which charges for reserves, but not for wind integration services. This is a classic case of the Company seeking to have retail customers subsidize wholesale services. Consequently, the OCS recommends disallowing these expenses. Mr. Hayet explains the details of this adjustment.

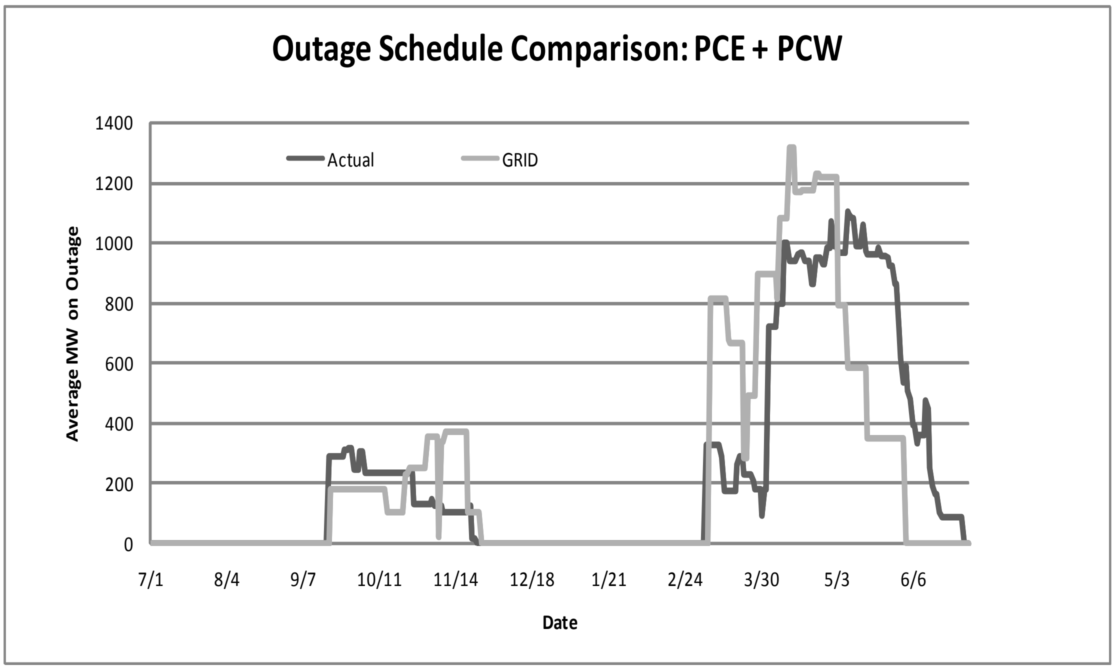
F. OUTAGE RATE MODELING ISSUES

<u>Adjustment 14. Planned Outage Scheduling</u>

Q. PLEASE DISCUSS THE COMPANY'S MODELING OF PLANNED OUTAGES IN GRID.

A. The Company uses a purely mechanical approach to determine planned outage schedules in GRID. This method is based on certain arbitrary inputs that determine a sequence of planned outages. The final outage schedule developed may or may not bear any resemblance to actual planned outage schedules. For example, in the 2007 case, the Company scheduled coal plant outages in high cost winter months, a practice virtually unprecedented in the Company's actual operations. Since that time, the Company has moderated its assumptions, but has not changed its methodology. In GRID, the Company typically schedules planned outages in GRID earlier in the year or in higher cost periods than in actual operation. Figure 3, below illustrates this problem during the test year.

Figure 3



Q. PLEASE EXPLAIN THIS FIGURE.

A. This chart shows the average capacity on outage for each day of the calendar year due to planned outages during the 48-month period ended December 31, 2008[28] compared to the GRID assumptions. It is apparent from the chart that actual planned outages have traditionally been scheduled in the spring and fall. The Company traditionally has scheduled most of its maintenance during April, May

[28] This was the four year period used by the Company to compute all outage rates.

and June. The Company's assumed planned outage schedule concentrates more of the planned outage energy in March and April, with less than actual in May and June. Offsetting this, however, is the slightly later scheduling of fall outages in GRID, as compared to actual.

Q. DO THESE ASSUMPTIONS IMPACT POWER COSTS IN THIS CASE?

A. Fortunately, they do not now appear to have a material effect. The reason for this is that the shape and level of the forward price curve has changed in the current forecast. If, however, forward prices revert back to prior levels and shaping, the Company's method may again substantially overstate NPC. I believe the disallowance in the prior case, as well as scrutiny by the Division and OCS has resulted in the Company being less aggressive in this case.

Q. WHAT IS YOUR RECOMMENDATION?

A. I am not now recommending any adjustments to the outage schedule for coal plants. However, if different assumptions are used in a later phase of this proceeding, an adjustment may then be warranted. In future cases, this issue may re-emerge as well. Although I am not recommending an adjustment in this case this should not be considered an endorsement of the Company's approach.

For the large new combined cycle plants, historical data doesn't provide a full four years of history to guide the outage schedule. Because the Company also has used and expects to use spring and fall outages for these plants, I assumed a spring outage for Currant Creek. There is also economic justification for this because scheduling the Currant Creek overhaul in the fall costs more than a springtime outage. A spring outage for Currant Creek was accepted by the Commission in Docket No. 07-035-93, and the supporting facts are still valid. In the case of Chehalis, the Company assumed the outage would occur during a period when the plant would not otherwise be dispatched, so no adjustment was needed.

Q. MR. DUVALL SUGGESTS THAT PARTIES AGREED TO TERMINATE THE PLANNED OUTAGE MODELING WORKSHOPS RESULTING FROM THE STIPULATION IN DOCKET 08-035-38. DO YOU AGREE?

A. No. Partway through the process the Company informed parties that it had no further plans to pursue the planned outage modeling process, citing litigation in other states. This was a unilateral decision on the part of the Company and not one agreed to by other parties.

Adjustment 15: Bridger Ramping

Q. DO YOU AGREE WITH THE INCLUSION OF RAMPING LOSSES FOR BRIDGER IN THE CALCULATION OF OUTAGE RATES?

A. No. The Bridger ramping loss adjustment should be removed because there are no generator logs available for the Company's share of these units to determine the actual ramping losses. See Exhibit OCS 4.4 for documentation. Further, review of the supporting data shows that during certain hours when ramping losses were assumed to occur, reserves were being allocated to Bridger. This is the same problem that led the Company to eliminate the ramping adjustment for its gas fired units in Docket No. 07-035-93. Finally, the exhibit also shows that on an hourly basis the Company's share of the plant output varies substantially from hour to hour. This demonstrates that either data being used is unreliable, or that the allocation of generation is not constant. Both are key assumptions in the Company's ramping loss calculation. In either case, the Company simply lacks reasonable data upon which to compute the Bridger ramping losses.

Adjustment 16: Minimum Loading and Deration Adjustment

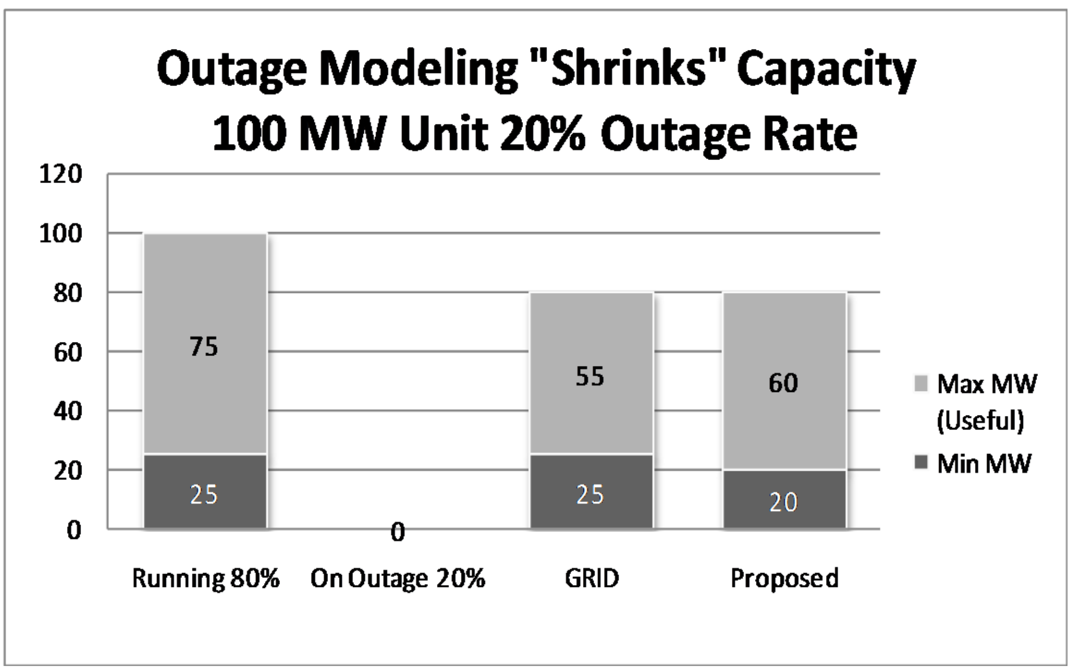
Q. WHAT IS THE PURPOSE OF ADJUSTMENT 16?

A. This adjustment implements an unresolved issue from Docket No. 07-035-93. It applies deration factors to unit minimum capacities and adjusts heat rates so they are not increased artificially due to modeling of forced outages. This approach is already used in industry standard models such as the MONET model used by Portland General Electric another regional utility company.

Q. WHY IS DERATION OF THE MINIMUM CAPACITY NECESSARY?

A. In GRID, forced outages are modeled by capacity deration. This amounts to "shrinking" the capacity to account for outages. For example, a 100 MW unit with a 20% forced outage rate is seen as an 80 MW unit in GRID.

Figure 4



The figure above illustrates this technique. The most useful capacity of a unit is the difference between the minimum and maximum capacity. This is the dispatchable capacity that can be used to provide reserves and follow load. Unless the minimum capacity is also derated by 20% (from 25 to 20 MW), the dispatchable capacity is understated. In the proposed adjustment, there is perfect symmetry: The maximum, minimum and dispatchable capacity are all derated by 20%. In the PacifiCorp method, maximum capacity is derated by 20%, minimum capacity by 0%, and the dispatchable capacity by 27%, a clearly asymmetrical result. The problem with the GRID method is that it assumes that during outages the maximum capacity of the unit is zero, but that the minimum capacity is still available. This leads to situations where the maximum capacity is less than the minimum capacity in GRID, producing unreasonable results. This scenario has occurred in this case, and in several prior cases. This is shown in Exhibit OCS 4.5, to be discussed later.

Q. DOES THE COMPANY METHOD OVERSTATE GENERATION AT MINIMUM CAPACITY?

A. Yes. Assuming the same facts as above, if the unit would ordinarily run at minimum capacity (25 MW) for 1000 hours, in GRID it would produce 25,000 MWh. In actual operation, the unit is on outage 20% of the time, and can only produce 20,000 MWh when running at minimum loading. The proposed adjustment is necessary to properly compute the generation of units when they are dispatched at minimum capacity.

Q. DOES THE CAPACITY DERATION ALSO IMPACT MODELING OF HEAT RATE CURVES?

A. Yes. A second problem with the GRID modeling is that when the capacity of units is derated it creates a mismatch between the size of the unit and the heat rate curve. The confidential chart below shows what happens when a heat rate curve sized for the full capacity of the unit is applied to the smaller (derated) capacity as modeled in GRID. Generators are typically more efficient at their maximum capacity, and less efficient at lower capacity levels. At the derated capacity used in GRID the efficiency is frequently reduced. In the example shown (based on Currant Creek) the heat rate at full capacity is increased by about confidential because the capacity of the unit has been reduced from confidential (full capacity) to confidential (the maximum derated capacity in GRID based on a conf outage rate). This is a level typical of recent GRID inputs. The GRID modeling makes units appear to be less efficient because they don't ever achieve operation at full capacity. Exhibit OCS 4.5 provided documentation that the proposed adjustment improves the accuracy of heat rates modeling in GRID as compared to actual results.

Figure 5 Confidential

Q. DOES THE HEAT RATE CURVE ADJUSTMENT ALSO IMPACT OTHER CAPACITY LEVELS IN GRID?

A. Yes. The heat rate curve adjustment is computed so that the heat rate curve for the derated capacity levels is identical to the unadjusted heat rate curve at the corresponding underated capacity level. For example, the adjusted heat rate at the derated minimum and derated maximum capacity is identical to the unadjusted heat rate at the underated minimum and maximum capacity. This is important because in GRID the great majority of energy is produced when units are simulated as running at minimum or maximum capacity. In GRID 74% of all fuel cost is incurred when units are simulated as running at maximum capacity, while 6% is produced when units are running at minimum. These two capacity states therefore account for 80% of all fuel costs, and about 87% of the proposed adjustment. Most of the remainder of this adjustment is accounted for by the deration of the minimum capacity.

Q. PLEASE DESCRIBE EXHIBIT OCS 4.5.

A. This issue presents a complex topic, but one which has now been litigated in two prior cases, and in other states. For this reason, the discussion here has been brief. There are, however, some technical issues surrounding this adjustment that have been addressed elsewhere. The exhibit provides various documents addressing certain aspects of this problem that may be useful for the Commission to consider. In the end, they demonstrate the reasonableness of the proposed adjustment. I also request that the Commission incorporate by reference my testimony related to this topic from Docket 07-035-93 and 08-035-38 into the record in this case. This includes: Direct Testimony of Randall J. Falkenberg in Docket 07-035-93, pages 86-86, lines 1966-2056 and Exhibit CCS4.16; Surrebuttal Testimony of Randall J. Falkenberg in Docket 07-035-93, pages 26-31, lines 656-803; Exhibit CCS 4.2SR, CCS 4.3SR; Direct Testimony of Randall J. Falkenberg in Docket 08-035-38, pages 41-51 lines 1019 -1252, Exhibits CCS 4.7(a-c) and CCS 4.8.

<u>Adjustment 17: Combined Cycle Plant Outage Rates</u>

Q. EXPLAIN THE BASIS FOR ADJUSTMENT 17.

A. Outage events during the initial operation of a new plant are typically higher than in subsequent years. This is a well known phenomenon in the industry, often called plant “maturation.” Usually there is a “shake down” period for new plants, when more outages occur. To develop the best forecasts, adjustments should be made to exclude the higher outages that occur during the initial operation of the new plant. Currant Creek, Lake Side and Chehalis don’t have a sufficiently long operating history to compute outage rates based on four years of mature plant operation. As a result, I have excluded outages during the first year of operation, and computed a blended outage rate based on the remaining actual data and the Company’s estimate of a mature outage rate. This adjustment was recently proposed by PacifiCorp in Oregon Docket No. UE 207, and was subsequently accepted by all parties in a partial settlement of another Oregon docket (UM 1355.) That case was initiated to develop better outage rate forecasting methods. Unlike other typical “black box” settlement agreements, this agreement will dictate future modeling practices in Oregon and thus represents an agreement on principles and methodologies.

<u>Adjustment 18: NERC EFOR$_d$</u>

Q. PLEASE DISCUSS THE NERC EFOR$_d$ FORMULA.

A. This is an industry accepted formula for computing outage rates of peaking plants. This formula is useful because the formula used in GRID overstates outage rates for resources that have frequent reserve shutdowns. In Oregon Docket UM 1355, there was agreement among all parties to compute outage rates for peaking plants using the NERC EFOR$_d$ formula. The Company also proposed use of this formula in Oregon Docket UE 207. I recommend this approach also be used in Utah, as shown in Adjustment 18.

G. SUMMARY OF RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I have made a number of recommendations resulting in adjustments to the Company's NPC, as shown in Table 1. In addition, I have made certain recommendations that did not result in specific adjustments. Below, I summarize these recommendations.

1. I recommend the Commission require the Company to justify its judgmentally determined market caps for Mona in its next rate case.

2. The final screens in GRID are sensitive to market caps, forward prices and other significant adjustments. The Commission should require the Company to re-compute screens for all applicable units in any final approved GRID run or updates allowed in this case, particularly if different market caps or forward prices are used. The Company has agreed elsewhere that this is an appropriate method for dealing with new information.[29/]

[29/] This was discussed during a conference call, August 14, 2009, and affirmed in Response to ICNU 10.33, OPUC Docket No. UE-207.

3. I recommend that the Commission require the Company to incorporate into its next rate case either a solution to the commitment logic error in GRID or the minor GRID modification to export the hourly sum of fuel and purchased power costs less sales revenue to facilitate screen development.

4. I recommend the Commission require the Company to present a comparison of the prior (GRID based) hydro shaping, as compared to the new (VISTA based) hydro shaping in the next general rate case. The Company should be required to provide GRID inputs to allow parties to run the model under either modeling method.

5. I continue to recommend that non-firm transmission be included in GRID.

6. I recommend the Commission continue to monitor the planned outage modeling assumptions used in GRID in future cases, and not endorse the methodology used in this case, even though I have not recommended any adjustment related to coal-fired generator inputs.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.