Witness CCS 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, Consisting of a General Rate Increase of Approximately $161.2 Million Per Year, and for Approval Of a New Large Load Surcharge	)))))))))	**Docket No. 07-035-93** **Direct Testimony of Randall J. Falkenberg On Behalf of the Utah Committee of Consumer Services**

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REDACTED CONFIDENTIAL INFORMATION INDICATED BY *******

April 7, 2008

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DIRECT TESTIMONY OF RANDALL J. FALKENBERG

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q. 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 Utah Committee of Consumer Services ("Committee").

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 AND APPEARANCES.

A. My qualifications and appearances are provided in Exhibit CCS 4.1. I have participated in and filed testimony in numerous cases involving PacifiCorp net power cost issues over the past ten years.

I. INTRODUCTION AND SUMMARY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A**.** My testimony addresses PacifiCorp's Generation and Regulation Initiatives Decision ("GRID") model study of normalized Net Variable Power Costs ("NVPC") for the projected test period, January 1 through December 31, 2008. I also incorporate NVPC adjustments proposed by Committee witness Mr. Philip Hayet into the GRID model as well.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. We have identified and quantified approximately 30 adjustments to the Company's GRID study (and overall revenue requirements) summarized in more detail below and on Table 1 shown later in this testimony. Utah Jurisdictional impacts are shown in parenthesis.

<u>Net Variable Power Costs (GRID)</u>

1. **PacifiCorp's request for $1050.7 million in (total Company) NVPC is overstated by $59.5 million. I recommend NVPC of $991.2 million, resulting in a reduction to Utah allocated NVPC of $25.0 million.**

<u>GRID Commitment Logic (Uneconomic Operation)</u>

2. **GRID portrays the PacifiCorp system as being heavily constrained by firm transmission and market capacity limits. Such constraints increase NVPC by preventing the sale of surplus generation and result in generators running inefficiently at minimum loading levels.**

3. **In actual operation these constraints may not exist because non-firm transmission capacity is often available. However, the Company excludes non-firm transmission from GRID for purposes of establishing normalized power costs. For this reason, GRID modeling results may differ substantially from actual results. The Commission has already ordered the Company to include non-firm transmission for purposes of computing avoided costs. I recommend the Commission require the Company to do the same for the purpose of computing NVPC for its next general rate case.**

4. **Although GRID is intended to simulate the <u>least cost</u> operation of the PacifiCorp system, it fails to do so. GRID makes unit commitment (start up and shut down) decisions ignoring transmission and market capacity limits. In contrast, the subsequent dispatch of units in the Linear Programming ("LP") module recognizes these constraints. As a result, GRID commits units to make undeliverable sales, increasing NVPC.**

5. **The Company has tried a variety of ad-hoc remedies to address this problem. These include logic changes, data adjustments, and acceptance of a variety of rate case adjustments. However, the GRID model still manifests the same problem even after the Company's various corrections. Unfortunately, the Company continues to address the symptoms of this problem rather than the cause.**

6. **I present an interim solution to this problem. My proposed solution is to systematically de-commit resources during periods of uneconomic generation. These adjustments impact the West Valley, Lake Side and Currant Creek units as well as certain call option contracts. The solution I propose is simple, but effective. Items 1-3 (summing to -$8,519,156 Utah) on Table 1 implement my corrections. Because these adjustments result in additional starts for the combined cycle units I also reflect increase overhaul and start up fuel costs in NVPC. These additional costs are shown as item 4 (+$3,951,914 Utah) on Table 1.**

<u>Long Term Firm ("LTF") and Short Term Firm ("STF") Contract Adjustments</u>

7. **PacifiCorp includes several uneconomic call option contracts in the GRID study. The Company proposed to remove certain costs of these contracts in the 2007 Oregon case,[1] but has not done so in this proceeding. I recommend the Company's Oregon proposal be applied after reversing uneconomic generation of these call options. This reduces NVPC by the amount shown as item 5 (-$1,053,407 Utah) on Table 1.**

8. **The Company overstates the level of losses resulting from the wheeling of Hermiston generation over the BPA network. This adjustment is presented in Table 1 as item 6 (-$440,407 Utah).**

9. **The Company incorrectly models the Sacramento Municipal Utility District ("SMUD") contract. The Company assumes SMUD will take power at only the highest cost hours of the year ignoring the historical pattern of delivery. Also, the Company overstates SMUD annual energy requirements. Correcting these problems results in the adjustments shown on Table 1 as items 7 (-$1,091,920 Utah) and 8 (-$14,239 Utah).**

10. **Mr. Hayet's proposes adjustments related to the SMUD contract pricing, the Sunnyside contract, cost savings from non-generation agreements with the Biomass qualified facilities (QF) and the Schwendiman contract delay . These adjustments are also reflected in Table 1 as items 9-12 (summing to -$2,779,239 Utah).**

11. **I recommend imputation of STF arbitrage and trading profits, based on historical results for the period 2004-2007.[2] Table 1 shows the value of this adjustment as item 13(-$1,508,883 Utah).**

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[1] 2007 Oregon NVPC update case (Docket UE 191).

[2] The Oregon Commission also adopted this adjustment in UE 191.

<u>Planned Outage Schedule</u>

12. The planned outage schedule used in GRID is based on arbitrary and unrealistic assumptions. Coal unit outages are scheduled in high cost periods in the winter and early fall in GRID, rather than predominately in lower cost periods in the spring, contrary to actual practice. I propose a lower cost outage schedule that is more consistent with the actual outage patterns. My proposed schedule also better addresses constraints faced by the Company in developing its outage schedule. Item 14 (-$4,627,055 Utah) on Table 1 quantifies the value of this adjustment

<u>Hydro Modeling</u>

13. The Company uses inconsistent data series, spanning different time periods, to develop the hydro inputs for GRID. This reduces hydro generation available compared to a consistent data set for the most recent forty water years (1964 to 2003) available.

14. The Company's hydro modeling methodology uses three scenarios representing Wet, Median, and Dry hydro conditions. However, the Company greatly overstates the likelihood of the Wet and Dry hydro scenarios. At a minimum, I recommend use of the Company's median hydro scenario only.[3] The best solution, however, would be to correct the weights used in the GRID model to more accurately reflect the relative probabilities of the three scenarios. Item 15 (-$1,461,392 Utah) on Table 1 shows the reduction to NVPC based on use of the proper weights.

15. The Company uses arbitrary and unsupported input parameters to overstate hydro reserve allocations. Reversing this input reduces NVPC by the Company shown on Table 1 as item 16 (-$489,430 Utah).[4]

<u>Forced Outage Rate Modeling</u>

16. The Company computes outage rates for GRID based on actual outages for the 48 months ended June 30, 2007. However, the Company proposes to model <u>monthly</u> variations in unplanned generator outage rates based on four years of historical data. This approach is contrary to standard industry practice and is unsupported on any statistical or engineering basis. Reversing this data change increases NVPC by the amount shown on Table 1 as item 17 (+$374,121 Utah).

[3] This is an approach recommended by the Company in Docket No. 04-035-42. It would result in a reduction to NVPC of $664,362 on a Utah basis.

[4] While I present this issue for the Commission's, I do not currently deduct it from my recommended total NVPC. This will be discussed subsequently in my testimony.

17. Over the past decade, outage rates for PacifiCorp units have substantially increased, resulting in much higher power costs. Based on review of Root Cause Analysis ("RCA") reports and data the Company files with NERC, I've determined that a single plant, Jim Bridger, is responsible for over half of the outages reported as being due to employee or contractor errors. Outages of this type at Bridger greatly exceed NERC averages. I recommend the Commission reduce outages at Bridger to bring them in line with NERC averages. Item 18 (-$525,855 Utah) on Table 1 quantifies this adjustment.

18. The Company proposes to include an adjustment for ramping of generators after shutdowns. This adjustment is not industry standard practice and was recently rejected by the Washington Utilities and Transportation Commission. Further, the Company calculation of its ramping adjustment is demonstrably wrong and greatly overstates any energy that might be lost due to ramping. Item 19 (-$1,675,929 Utah) on Table 1 quantifies the impact of reversing the Company's ramping adjustment.

<u>**Currant Creek and Lake Side Modeling**</u>

19. The Company has ignored the reserve carrying capability of Currant Creek when operating in duct firing mode. Further, GRID allows duct firing to operate before the steam generator is running at full load. This is an unrealistic and inefficient mode of operation. Addressing this problem reduces NVPC by the amount shown as item 20 on Table 1 (-$1,509,336 Utah).[5]

20. The Company has used an incorrect and unsupported formula to compute the Currant Creek outage rate. The Company has also incorrectly computed the planned outage requirements for Currant Creek. Correcting these problems reduces NVPC by the amount shown on Table 1 as item 21 (-$92,565 Utah).

<u>**Generating Unit Representation in GRID**</u>

21. GRID derates maximum generator capacities to reflect unplanned outages. While this is an industry standard technique, the Company must also derate unit minimum capacities, and make an adjustment to heat rates to properly model the impact of unit outages on generator cost and performance. These adjustments result in a reduction to NVPC by the amount shown on Table 1 as items 22 (-$1,517,855 Utah) and 23 (-$455,858 Utah).

[5] Id.

22. I recommend the Commission remove the station service transaction from GRID. This adjustment models station service during outages as a zero revenue sale. The Company's approach is contrary to industry standard practice and differs from the method already used in GRID to model over 99% of station service energy. The industry standard technique is to adjust heat rates to reflect station service requirements. Making this correction to GRID reduces NVPC by the amount shown on Table 1 as item 24 (-$641,121 Utah).

Other NVPC Adjustments

23. The Company has substantially overstated wind integration costs. The Company incorrectly applied a formula from the IRP basing the wind integration costs on 2000 MW of installed wind capacity, rather than Test Year levels which are far below 1000 MW. Correcting this problem results in the adjustment shown as item 25 (-$711,400 Utah) on Table 1.

24. The Company has included reserve requirements in GRID for certain generators in its control area that self supply reserves or provide no compensation to the Company. Removing these reserve requirements from GRID results in the adjustment shown as item 26 (-$920,295 Utah) on Table 1.

25. I correct transmission wheeling expense pro-forma adjustments related to the Goodnoe wind project and the Borah-Brady transmission upgrade. Further, transmission expense escalations in GRID have been overstated. Finally, the Company has ignored the benefit of transmission imbalance charges it collects, which provides a source of below market energy. These adjustments are shown as item 28-30 on Table 1 (summing to -$1,312,839 Utah).

Table 1
Summary of Recommended Adjustments
$1000

	Total Company		Est. Utah Jurisdiction
		SE	41.700%
		SG	42.482%
I. GRID (Net Variable Power Cost Issues)			
1 PacifiCorp Request NPC - GND-15	1,050,698,899		
A. GRID Commitment Logic			
1 Uneconomic West Valley Operation	(664,752)		(279,801)
2 Uneconomic Currant Creek Operation	(11,513,988)		(4,846,353)
3 Uneconomic Lakeside Operation	(8,061,112)		(3,393,003)
4 Incremental Start Up Costs CC and LS	9,388,977	*	3,951,914
B. STF and LTF Contract Adjustments			
5 Call Options	(2,502,690)		(1,053,407)
6 Hermiston Loss Adjustment	(1,046,320)		(440,407)
7 SMUD Contract Normalization	(2,594,189)		(1,091,920)
8 SMUD Leap Year Adjustment	(33,829)		(14,239)
9 SMUD Contract Repricing	(2,382,720)		(1,002,911)
10 Biomass Non Gen Agreement	(457,702)		(192,651)
11 Sunnyside Contract	(3,642,330)		(1,533,093)
12 Schwendiman Contract Deferral	(120,176)		(50,583)
13 STF Arbitrage and Trading Profits	(3,584,812)		(1,508,883)
C. Planned Outage Schedule			
14 Planned Outage Schedule	(10,992,980)		(4,627,055)
D. Hydro Modeling			
15 Proper Hydro Weighting	(3,471,982)		(1,461,392)
16 Hyrdo Reserve Input Parameter**	(1,162,790)		(489,430)
E. Outage Rate Modeling			
17 Monthly Outage Rate	888,839		374,121
18 Bridger Error Outages	(1,249,330)		(525,855)
19 Ramping	(3,981,680)		(1,675,929)
F. Currant Creek and Lakeside Modeling			
20 Duct Firing Reserve Capability/Combine CC+DF**	(3,585,888)		(1,509,336)
21 Currant Creek Outage Rates	(219,917)		(92,565)
G. Generating Unit Representation in GRID			
22 Heat Rate Modeling Adjustment	(3,606,126)		(1,517,855)
23 Minimum Loading Deration	(1,083,029)		(455,858)
24 Station Service in Heat Rate Curve	(1,523,178)		(641,121)
H. Other NVPC Adjustments			
25 Wind Integration Charges	(1,690,147)		(711,400)
26 Remove Self Supply Non-Owned Reserve	(2,186,441)		(920,295)
27 Goodnoe Transmission Pro Forma	(1,072,352)		(451,364)
28 Borah Brady Transmission Pro Forma	378,805		159,443
29 Transmission Cost Escalation	(1,543,645)		(649,736)
30 Transmission Imbalance	(881,832)		(371,172)
Subtotal Power Cost Adjustments -	(59,450,639)		(25,023,369)
Allowed - Final GRID Result*	991,248,260		
* Includes start up fuel in the amount of	5,296,977		2,208,840
** Adjustment not deducted from Final GRID Result			

Q. PLEASE DESCRIBE YOUR ANALYSIS OF NVPC IN THIS CASE.

A. Mr. Hayet and I have performed a comprehensive “model audit” of GRID and the database used in this case. We have participated in every PacifiCorp Utah general rate case since 1998, directing our attention to the reasonableness of the Company’s determination of NVPC using various power cost models. To perform this project, we obtained the current version of the GRID model and associated documentation, and conducted numerous model runs and analyses of the input and output data. We issued approximately 275 data requests, and on February 14 and 15, 2008 conducted on-site interviews with Company personnel from the Net Power Cost group, the Commercial and Trading Department, the Fuels Department, and the Operations Department.

Q. IN GRID, DOES THE SEQUENCE IN WHICH ADJUSTMENTS ARE RUN MATERIALLY IMPACT THE RESULTS PRODUCED BY THE MODEL?

A. No. The final results do not matter on the order of adjustments. However, the sequence in which individual adjustments are run in GRID can result in differences in their impact. This is due to changes in “balancing” of the system.

Q. HAVE YOU INCLUDED THE EFFECT OF BALANCING ON THE ADJUSTMENTS YOU PROPOSE?

A. For adjustments that can be computed within the model, I have. Certain adjustments, such as the short-term firm arbitrage and trading profits adjustment, are computed external to GRID.[6] As a result, there should not be any substantial balancing effects remaining. However, it is important for the Commission to

[6] These include adjustments 4, 5, 13, 15, a small part of 18. These adjustments are computed externally with data outputs from GRID. Adjustments 9 and 28-30 are simply adjustments to fixed cost figures that are reported in GRID, and don’t require a model run to implement.

recognize that the level of these adjustments is not only dependent on the order in which they are performed, but also on the adjustments ultimately allowed. As a result, the figures shown on Table 1 are indicative of results that would be obtained in a final GRID run for this case, but to the extent the Commission doesn’t accept all of the proposed adjustments, or the order of adjustments is changed, there will likely be changes to individual adjustments.

II. GRID STRUCTURE AND LOGIC ISSUES

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

A. Net variable power costs are the variable production costs related to fuel and purchased power expenses and net of sales revenue. The Company estimated these costs for the Calendar Year 2008 test period using the GRID model. NVPC comprise a substantial portion of the overall revenue requirement and therefore are a significant component of PacifiCorp's proposed base rates.

GRID Overview and Issues

Q. WHAT IS THE PURPOSE OF GRID?

A. The purpose of the GRID model is to estimate NVPC by modeling the least cost operation of the PacifiCorp resources, subject to serving load and all applicable constraints. This is clearly stated in the GRID Algorithm Guide:

> **"GRID (Generation and Regulation Initiative Decision Tools) is a production cost model that *dispatches PacifiCorp resources to serve load obligation through the most economic means*. Core functions include:**
>
> - **Committing thermal generating units against market price**
> - **Shaping hydro generation against net system load**
> - **Shaping long-term firm contract energy per contract terms against market price**
> - **Calculation and satisfaction of reserve requirement**
> - ***Balancing and optimization of the Company's resources given transmission and market constraints, including market purchases and sales*"** (emphasis added) [7]

The above stated description is typical of the mainstream utility production cost models in use in the industry today. As a matter of course such models assume system operating costs are minimized subject to operational constraints, such as

[7] GRID Algorithm Guide, V6.2, dated December 2007, as supplied by PacifiCorp on the GRID computer, page 4.

transmission limitations. Simulation of the "least cost" operation of the system is the paradigm assumed by all industry standard production cost models and is the stated goal of the GRID model.

Q. DOES GRID SIMULATE ALL OF THE RESOURCES AVAILABLE TO THE COMPANY?

A. No. Most notably, the Company ignores available non-firm transmission resources. In its response to CCS Data Request 2.10, the Company stated that it did not include non-firm transmission because it is "*not known-and-measurable under normalized rate-making*." Further, in the responses to CCS 2.11 and 2.12, the Company indicated it could not distinguish between the firm and non-firm flows, and instead represents only firm transmission rights in GRID. The Company further stated that it had performed no studies to estimate the amount of non-firm energy that could flow over the transmission links modeled in GRID.

Q. WHAT ARE THE IMPLICATIONS OF EXCLUDING NON-FIRM TRANSMISSION?

A. First of all, the transmission flows modeled in GRID will be quite different from those that actually take place and the two are not comparable. (See, again, the response to CCS 2.11). This implies that the distribution of generation among the Company's resources may be quite different from actual results as well. In effect, the Company is separating the actual operation of the system from its normalized modeling results in GRID. In this, and many other instances, the Company's approach to GRID actually deviates from the intended purpose of normalization.

Q. IS THIS REASONABLE?

A. No. Certainly, it is not known exactly what non-firm transmission will be available to the Company during the Test Year. However, the same is true of nearly any other input in GRID. For example, market availability and the price for non-firm balancing power are not known and measurable either. For that matter, we do not know what customer loads will be, what unplanned generator outages will occur, or what fuel costs will be. Despite this uncertainty, the Company performs power cost studies with GRID using historical data as a guide to prepare inputs and (hopefully) make sound choices about each and every data input. It makes no sense to perform highly detailed projections of the generation system using literally hundreds of thousands of data inputs, yet ignore a vital element of the resources available.

Further, excluding non-firm transmission will certainly serve to increase NVPC because, like market purchases, the Company need only avail itself of these resources when they enable cost savings. The lack of non-firm transmission capacity also may result in certain constraints arising in GRID, which may not exist in real-time operations. These issues will be discussed in depth shortly. Failure to model non-firm transmission presents a source of systematic bias in GRID, and limits the usefulness of comparisons of GRID results to historical data.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION?

A. In a recent avoided cost case, Docket No. 03-035-14, the Commission required the Company to start calculating avoided costs using a 48 month history of non-firm transmission. (Order, Docket No. 03-035-14, page 14.) I recommend the

Commission order the same requirement for GRID studies used in the next Utah general rate case.

Q. DOES GRID ACTUALLY ACCOMPLISH ITS GOAL OF SIMULATING COST MINIMIZATION GIVEN THE SYSTEM CONFIGURATION IT MODELS?

A. No. GRID frequently fails to develop the least cost operation of resources. In fact, there are thousands of hours per year when gas-fired generators are not operating economically within the model. This results in a spillover effect to coal-fired generation. Frequently, the uneconomic operation of gas plants forces lower cost coal units to have their output curtailed. I estimate the model produces additional costs of nearly $11 million dollars due to this problem alone, or about 1% of total NVPC.

Q. DO UTILITIES ALWAYS SUCCEED IN MINIMIZING COST IN REAL TIME OPERATION?

A. No. There are always instances where forecast errors, unexpected outages or other problems result in suboptimal real time operation. However, the goal is to minimize costs to customers.

Q. DO INDUSTRY STANDARD MODELS ASSUME OPTIMAL OPERATION OF RESOURCES AND COST MINIMIZATION DESPITE THE FACT THAT IT CAN'T ALWAYS BE ACHIEVED IN PRACTICE?

A. Yes. All of the significant production cost models in use by the industry assume optimal scheduling and dispatch of all resources. There are at least three reasons for this. <u>First</u>, utilities have a fiduciary responsibility to minimize costs for ratepayers. Models assume this responsibility is met.

<u>Second</u>, there is no evidence demonstrating that utilities have consistently failed to minimize costs. While cost minimization may not be perfectly achieved,

there is nothing to suggest utilities systematically "miss the mark." In cases where they don't succeed in cost minimization, forecast errors (factors not considered in GRID) are almost always the cause.

Finally, in a modeling context, cost minimization is the only possible objective target. Building logic into models that systematically assumes costs are not minimized is even more problematical and is far too subjective. For example, should we assume in the model that system operation is only 99% or even less successful? Where would one draw the line? It becomes a very slippery slope once one begins to assume that performance of the system operators will be systematically deficient.

In cases where it is systematically impossible to optimize the operation of a given resource within the model, the proper approach is to identify the cause (such as a constraint), and insert additional logic to address the problem. Mr. Hayet and I have both worked on such issues at various times over the years.

Q. DO YOU BELIEVE THAT IN ITS REAL TIME OPERATIONS THE COMPANY DOES SEEK TO MINIMIZE OPERATING COSTS, SUBJECT TO CONSTRAINTS?

A. Yes. Mr. Hayet and I interviewed personnel from PacifiCorp's real time operations staff in Portland on February 15, 2008. We discussed, in depth, the techniques used by the Company to optimize unit commitment and dispatch decisions and did follow up discovery. It was stated that the Company believes instances of incorrect commitment and uneconomic generation, while possible, are rare events. I have no reason to doubt this. Indeed, I expect the Company makes every effort to achieve the least cost operation of the power system, subject to applicable constraints. It was also noted during this meeting that availability of non-firm transmission is a key element in the cost minimization process.

Q. WHAT CONSTRAINTS ARE MOST SIGNIFICANT IN GRID?

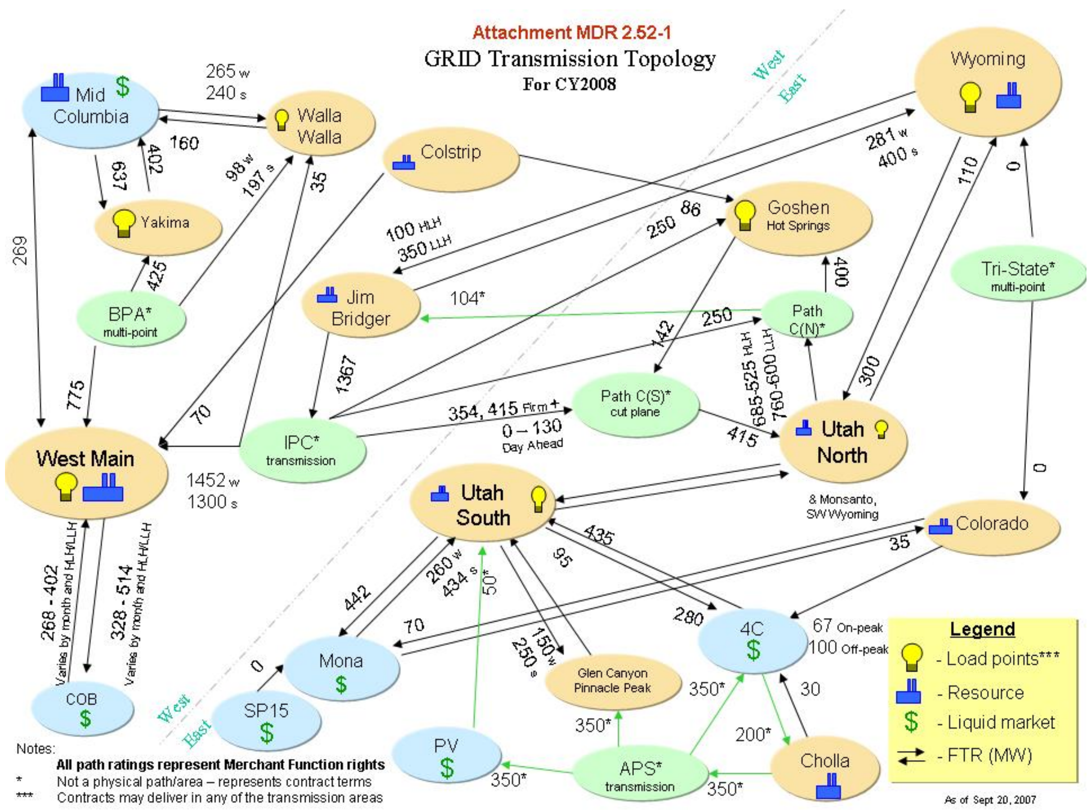
A. The most serious constraints are imposed by firm transmission limits and market caps.[8] These are significant because without the free flow of power across the transmission network or liquid markets for transactions, the Company cannot always sell available excess generation, purchase the least cost energy available, or operate units at their most efficient loading levels. The figure below shows a copy of the current GRID Transmission Topology Map.[9] This map shows the system is quite complex and all transmission paths have limited capacities.

In addition, there are various operating constraints, including unit minimum loading levels, reserve requirements, minimum up and down times for generators, and market liquidity limits (market caps). All of these factors are simulated in GRID, and are interrelated. For example, if the Company has excess generation, but is unable to sell the energy due to transmission constraints, units are required to reduce output. In such instances units may be dispatched in GRID at their minimum loading levels, which is typically their least efficient loading.

[8] Market caps represent limits on the amount of energy that can be sold in a given market. In GRID market caps are applied during the hours 1-6 am, based on historical data. I have concerns about the development of this data, but did not address that in this case.

[9] MDR 2.52-1.

Figure 1: GRID Transmission Topology Map MDR 2.52-1



Q. PLEASE PROVIDE EXAMPLES OF TRANSMISSION LIMITATIONS THAT RESULT IN OPERATIONAL CONSTRAINTS WITHIN GRID IN TERMS OF RUNNING GENERATION RESOURCES?

A. GRID simulations reveal that several of the key transmission links are heavily constrained. As shown in Exhibit CCS 4.2: the Utah South to Four Corners link is constrained 5478 hours per year; the Cholla 4 to APS link is constrained 4517 hours per year; the Bridger to Idaho link is constrained 2870 hours per year; and Colstrip to West Main is constrained 6306 hours per year. Further, owing to market capacity limits assumed in GRID, there are additional constraints that occur (and are generally binding) every day for five hours, from 1 am until 6 am.

The net result of these constraints in GRID is that PacifiCorp generators frequently run at minimum loading levels. For example, Currant Creek is assumed to be operating at its minimum loading (340 MW) more than 4200 hours per year, or more than 60% of the time the unit is running. Lake Side is shown to be operating at minimum more than 2100 hours per year (28% of all operating hours). The Gadsby and West Valley combustion turbines are shown as running at minimum 67% to 91% of the time they are operating. The above examples are provided in Exhibit CCS 4.3.

Even coal plants are shown to frequently be operating at minimum loadings in GRID. For example, GRID results show Carbon 1 operating at minimum loading more than 2000 hours per year (24% of total operating hours), Hayden 2 operating at minimum loading for more than 2100 hours (26% of total operating hours) and Naughton 2 operating at minimum loading for more than 1600 hours (20% of total operating hours).

Q. ARE THESE GRID RESULTS REALISTIC?

A. No. Exhibit CCS 4.3 also shows that in actual operation, the Company generators run at minimum loadings far less often than is portrayed by the GRID model. It is also quite telling that GRID also shows the Currant Creek and Lake Side duct firing capabilities operating for hundreds of hours, when the steam generators are being dispatched at minimum loadings. All of this suggests a serious problem with the dispatch and commitment logic in GRID.

Q. EXPLAIN HOW YOU COMPUTED THE HOURS OF OPERATION AT MINIMUM LOADING IN EXHIBIT CCS 4.3.

A. For the GRID model it is quite simple to compare the hourly dispatch of units to their minimum loading input. In actual operation, it’s more complicated because units don’t run exactly at the minimum loading over even a single hour, due to varying conditions, ramping and hourly load swings. As a result, I established upper and lower limits, centered on the GRID minimum loading input, and counted how many hours units operated within that range. I looked at both a 10% and 20% range, which provide a very broad window. For example, for Cholla (with an assumed minimum loading of 250 MW in GRID) the 10% range was 225 MW to 275 W. Anytime the hourly dispatch fell in that range, it was counted as an hour at minimum loading. The 20% range was even larger (200-300 MW.) Even with these expanded ranges, the actual hours of operation at minimum loading generally fell well below the GRID model results. This clearly indicates the GRID model is portraying far more hours of operation at minimum loadings than actually occurs. This provides indirect evidence of uneconomic operation in GRID. However, there is direct evidence of this problem that is readily available that demonstrates GRID does not “normalize” unit operations as compared to actual experience.

Q. DESCRIBE THE DIRECT EVIDENCE OF UNECONOMIC GENERATION IN GRID.

A. As I previously discussed, GRID is supposed to simulate the *least cost* operation of system resources. If it costs less to *not* run a particular unit for a particular period of time, the model should simply not commit it in the first place. This is particularly true of gas-fired units, which have the ability to cycle on a daily basis. To provide a proper modeling, the daily decision to start up a unit (in GRID) should reduce not increase NVPC, unless it is needed for purposes of meeting reserve requirements. Yet, I found that when certain resources are removed from GRID in certain months or at certain times, NVPC actually declined. In GRID units are started up (or left running) that are not needed for reliability purposes, and which are not part of the least cost operation of the PacifiCorp system. This is a clear cut error in the implementation of the model.

Q. PLEASE PROVIDE EXAMPLES OF THIS PROBLEM?

A. The most significant problem concerns the modeling of Currant Creek. While GRID shuts down the Currant Creek plant more than 200 nights of the year, it does leave the plant running the remaining nights. A run that required the Currant Creek plant to shut down every night produces substantially lower NVPC. Further, a run performed without the West Valley CT units produced NVPC lower than the run including those units in April and May 2008. Removal of the NEBO heat rate contract energy from GRID (while retaining the contract demand charges) produced lower NVPC in March 2008. A GRID run removing the Constellation 257687 Call Option Contract (while retaining the contract demand charges) produces equal or lower NVPC every single month from June to September 2008. Finally, removal of the Duct Firing capability of Currant Creek produced lower NVPC in certain months. In all of these cases, GRID would produce lower production costs if the resources were simply not available to run during the time periods discussed. These examples clearly show that a serious problem relating to uneconomic generation exists in GRID.

Q. IS OPERATION OF THESE UNITS REQUIRED FOR MEETING RELIABILITY REQUIREMENTS IN GRID?

A. No. In GRID, reliability requirements are modeled by specifying an hourly reserve capacity requirement. GRID computes hourly "Reserve Shortage" if there is not enough capacity on line to meet reserve requirements.

The Company assumes that the NEBO and Constellation contracts and duct firing capability of Currant Creek do not provide any spinning reserve capability. Consequently, there is no reliability basis for starting these units. In the case of Currant Creek, it makes little sense to assume the plant needs to run at night for reliability purposes. Further, review of the Reserve Shortage results from the GRID model shows no impact on reserves when these resources are removed. GRID simply uses other (already available) capacity to meet reserve requirements when these units are removed from the model. Therefore, the increased cost cannot be tied to a need to meet reserve requirements.

Q. IS IT POSSIBLE THIS PROBLEM IS RELATED TO OTHER OPERATING CONSTRAINTS, SUCH AS MINIMUM UP OR DOWN TIMES?

A. No. Again, all of the resources in question can cycle on a daily basis. Review of the GRID hourly dispatch results, shows that all applicable constraints were met.

Q. DO YOU KNOW WHY THIS PROBLEM IS OCCURRING?

A. The problem is occurring because the logic in GRID separates the decision to commit (start up or shut down) a resource from the operating constraints (transmission limits and market capacity limits) imposed in the model. However, these operating constraints are later used to determine the optimal dispatch of resources. The simplest explanation is the model unrealistically assumes energy produced by a generator can always be sold in various markets when making the commitment decision. As a result, units are running when there is no market for the energy they produce.

Q. EXPLAIN THE DIFFERENCE BETWEEN COMMITMENT AND DISPATCH IN GRID.

A. Commitment is the determination of which units are (or should be) running in a particular hour. Once the model determines a unit is committed (i.e. running), a unit must run at least at its minimum loading level. Dispatch is the determination of the level at which each of the committed units will actually run. Units generally are most efficient at or near full loading, and least efficient at minimum loading. The Linear Programming ("LP") module in GRID determines the dispatch of committed resources that minimizes total cost, subject to the constraints imposed. However, that the LP module does not decide which units *should* be running and cannot reverse an incorrect commitment decision made previously by the model.

Q. EXPLAIN HOW GRID SIMULATES THE COMMITMENT AND DISPATCH OF UNITS.

A. This is a two-step process. The model first develops a list of "committed" units for each hour. Once that step is completed, the LP module solves for the most efficient dispatch of resources, subject to transmission and other operating constraints (such as minimum loading requirements). Frequently, there are too many units committed during a specific hour and the model produces a dispatch that exceeds the least possible cost. As a result, removing certain units from the entire dispatch and commitment sequence can actually lower NVPC because GRID makes a mistake in deciding which units to start up in the first place.

This occurs because the commitment logic is premised on a comparison of market prices to the dispatch cost of individual resources. In effect, the model assumes that if a resource is started up, all of the additional energy produced by the unit can be sold at market prices or will offset Company owned generation costing that much or more.[10] However, transmission constraints and market caps, frequently limit the amount of energy that can be sold in the market, particularly the energy from resources in the Utah North and Utah South transmission areas.[11] This is the major source of uneconomic generation in the GRID model.

Q. EXPLAIN THE PROBLEMS RELATED TO THE UTAH TRANSMISSION AREA RESOURCES.

A. As shown in the topology map above, there is a vital transmission link available between the Utah resources and the Four Corners market hub. In GRID, the Company uses Four Corners as the reference market price for resources in the Utah transmission area.[12] GRID assumes that if a unit is started up, it will either be able to sell its energy in the Four Corners market (or will enable another, lower cost, unit to do so.)

Q. IS THAT A REALISTIC ASSUMPTION?

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[10] GRID Algorithm Guide, V6.2, dated December 2007, as supplied by PacifiCorp on the GRID computer, pages 47-53.

[11] While these are modeled as two separate areas in GRID, they have a very large transfer capability, thus constraints between these two areas are not a significant problem.

[12] Some resources, such as the NEBO contract use Mona as the reference price. However, market caps limit the ability to make sales in this area as well.

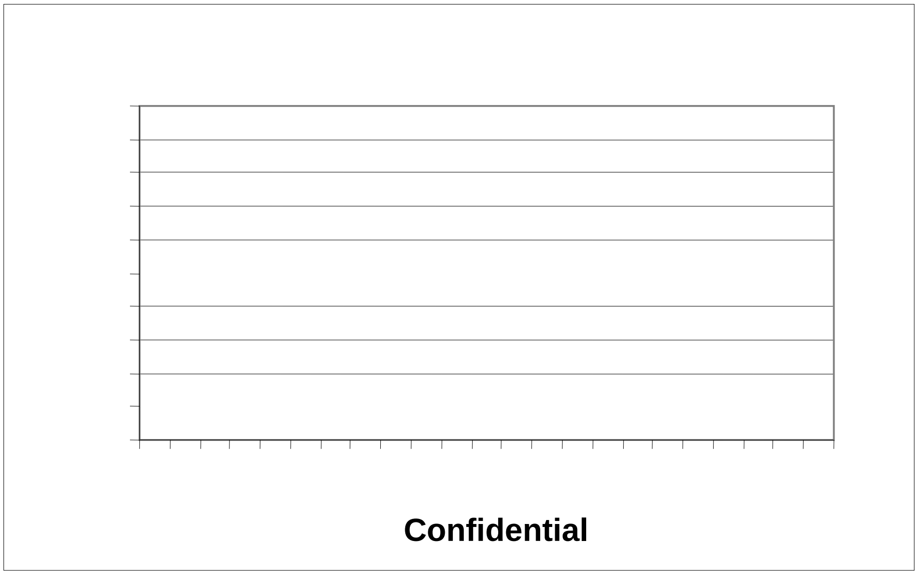
A. No, far too often it is a completely *unrealistic* assumption. As shown on Exhibit CCS 4.2, the Utah South to Four Corners link is constrained 5478 hours per year by transmission limitations. Further, market caps limit the ability to sell into this market 1465 hours per year (during the "graveyard shift" hours). Combined, this means there is no market for incremental sales to Four Corners 6943 hours during the test year, or close to 80% of the time. In effect, GRID starts up units in order to make additional sales, but there is no way to actually deliver that energy to the Four Corners market 5478 hours per year and no market another 1465 hours per year. For example, sales at night to Four Corners are limited by market caps to approximately 55 MW on average. However, the model frequently allows Currant Creek to continue to run at night, under the false assumption that it would be possible to sell output from the plant at market prices. This leads to a substantial and costly mistake in the simulation of Currant Creek operations, that I do not believe actually happens in real-time operations.[13]

Q. CAN YOU ILLUSTRATE THIS PROBLEM USING DATA FROM THE GRID MODEL?

A. Yes. The confidential graph below illustrates the problem, using Currant Creek.

[13] In real –time operation the availability of non-firm transmission capacity may enable sales to other markets, thereby avoiding the need to reduce energy from, or shut down, Currant Creek.

CONFIDENTIAL****************Figure 2**********

*

The graph shows the Four Corners market price, and the running cost of the Currant Creek unit as simulated in GRID for December 4, 2008. It further shows that the cost of energy from Currant Creek is quite close to the Four Corners market price every hour during the night time hours, and far below the Four Corners market price the rest of the day. Because start up fuel and O&M costs[14] are considered, and the plant must have a minimum six hour shutdown, GRID decides to keep the unit running at night. As such, GRID *comm*its the resource for the entire day.

In GRID once the list of committed units is developed for each hour, the LP module develops the least cost dispatch subject to the transmission and market capacity constraints. Based on the final LP solution, the Four Corners market capacity is constrained to the market size limit of 67 MW. Consequently, the maximum sales to the Four Corners market are made without Currant Creek, and

[14] These costs amount to approximately $***** per start.

additional generation from Currant Creek does not result in additional sales. Rather, if additional generation is committed (or in this case remains committed), it simply means that generation from other units must be reduced. This means the "avoided cost" of Currant Creek would equal the cost of the units whose capacity has been reduced, not the *much higher cost* of the energy transacted in the Four Corners market. As the chart shows, these avoided costs are much lower indicating that during the five nighttime hours limited by the market cap, the impact of running Currant Creek is to reduce the output of lower cost coal units, not to increase sales to the Four Corners market. As a result, it actually costs much more (in this case, $48,000 for the day based on my calculations)[15] to run Currant Creek at night, than to shut the plant down.

Q. EXPLAIN HOW THE FIGURES IN THE CHART WERE DERIVED.

A. The figure above computes the hourly avoided cost for Currant Creek by comparing the hourly sum of fuel and purchased power expenses, net of sales revenues in GRID runs with and without the resource. The graph above shows that from 6 am to 11 pm (hours that are not constrained by the market capacity limit) the Currant Creek avoided cost tracks the Four Corners market price, and both exceed the cost of energy from Currant Creek. It obviously makes great sense to run Currant Creek during these daytime hours. However, for "graveyard shift hours", the Currant Creek avoided cost is far below the value of Four Corners market energy. Consequently, running the plant at night does not

[15] Net of the cost of an additional start up.

produce additional sales during these hours, but instead, only serves to reduce the output of lower cost resources, *increasing* total NVPC.

Q. HAS THIS PROBLEM EXISTED IN THE MODEL FOR SOME TIME?

A. I believe so. However, its nature has not been fully understood in the past, perhaps not even by the Company. Further, the problem has recently gotten much worse due to load growth (resulting in increasing constraints on the system) and the addition of various resources on the system, including certain call options, Currant Creek and Lake Side. In fact, the Company has actually exacerbated the constraint problem because of the high minimum loadings assumed in GRID for Currant Creek, NEBO and Lake Side. Because GRID does not consider operating constraints when committing resources, Currant Creek, Lake Side and NEBO resources are operated in an uneconomic manner.

Q. PLEASE DISCUSS SOME OF THE PRIOR INDICATIONS OF THIS UNECONOMIC GENERATION PROBLEM.

A. As early as Wyoming Docket No. 20000-ER-03-198, Company witness, Mr. Widmer, acknowledged that combustion turbines were dispatched incorrectly in GRID and agreed in his rebuttal testimony to a $1 million disallowance to address the problem.[16] Similar issues have been raised in subsequent PacifiCorp cases, though most have been settled with regards to power cost issues.

In the most recent Oregon NVPC update case (UE-191), the OPUC adopted $9.96 million in disallowances directly or indirectly related to addressing

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16 Re PacifiCorp, Wyoming Public Service Commission Docket No. 20000-ER-03-198, Final Order at ¶ 35 a2 (Feb. 28, 2004).

the uneconomic generation problem. Exhibit CCS 4.4 shows the November 7, 2007 GRID update in the Oregon case referenced above. The final three adjustments listed in this exhibit (Uneconomic CT operation, Call Options and Carbon at 80% CF) are all symptomatic of the problem of uneconomic generation in GRID.

Q. HAS THE COMPANY ACKNOWLEDGED A NEED TO CHANGE THE GRID LOGIC IN ITS FILING IN THIS CASE?

A. Yes. In the Company' s direct testimony, Mr. Widmer (replaced now by Mr. Duval) testified that a change made in GRID "*enhances the system balancing logic to better recognize economic displacement by decommitting eligible thermal units. Previously, the Company used a manual workaround*."[17] In a subsequent telephone conversation in December 2007, Mr. Widmer confirmed the purpose of the logic change was to address the problem of too many units running at minimum loadings because commitment decisions in GRID did not consider operating constraints.

Q. DOES THE NEW LOGIC IN GRID 6.2 SOLVE THE UNECONOMIC GENERATION PROBLEM?

A. No. The new logic has done little to address the uneconomic generation problem. Indeed, GRID runs that I just discussed clearly show that the problem remains, even with the Company's latest "fix" invoked.

The new logic change does not address the problem of the failure to connect the commitment logic with operating constraints. Rather, it makes yet

[17] Utah PSC Docket No. 07-035-93, Widmer Direct Testimony, page 7. The "manual work around" is related to use of a "commitment fuel tier" to be discussed shortly.

another ad-hoc adjustment by de-committing units once a certain (judgmentally determined) level of capacity "displacement" is reached.[18] In this context "displacement" is the amount of capacity committed in excess of the actual requirement.

Q. PLEASE EXPLAIN THE OTHER DATA AND LOGIC CHANGES THE COMPANY HAS MADE TO ADDRESS THE UNECONOMIC GENERATION PROBLEM.

A. For some time the Company has prevented GRID from running combustion turbines during night time hours. Further, in the recent Wyoming case, the Company made a new ad-hoc adjustment to the commitment fuel cost in GRID in order to "trick" the model into reducing the number of starts of certain gas units. This is the "manual work around" discussed in Mr. Widmer's (Duval's) testimony in this case. Finally, the Company uses a "reserve credit" designed to stimulate the start up of certain units to free up lower cost units from providing reserves. I believe this calculation has been changed in recent GRID versions, but fails to solve (and may even exacerbate) the problem of uneconomic generation.

Q. IS THERE A LONG -TERM SOLUTION TO THIS PROBLEM?

A. Yes. The Company needs to change the GRID logic to harmonize the commitment decision process with the operating constraints. This may be rather difficult given the structure of the model. However, I recommend the Commission require the Company do so before it files its next Utah general rate case. Alternatively, if the Company files a GRID study using non-firm transmission

[18] See the response to CCS 6.39.

capabilities and this minimizes the impact of the uneconomic generation problem, new logic *may* not be as critical.

Q. HAVE YOU DEVELOPED AN INTERIM SOLUTION FOR THIS CASE?

A. Yes. For purposes of this case, I have developed an interim solution. My solution is illustrated in Exhibit CCS 4.5. Note that I am proposing the application of this methodology to the final GRID model adopted by the Commission, rather than just the specific inputs that I developed using this method. This will require that the Company make all other Commission-approved adjustments to the model, and then implement my proposed methodology in their final GRID runs.

Q. DESCRIBE THE METHODOLOGY YOU PROPOSE.

A. This solution rests on comparison of two GRID runs, with and without a specific resource, or group of resources. In Exhibit CCS 4.5, I show the calculation used for the West Valley units based on several days of operational data. On some days, West Valley is economic for the entire day, whereas in other days it would save money if the unit never ran. For simplicity purposes in this case only, I have decided to limit the analysis of the West Valley units and call option resources to a daily analysis. These are all resources for which the daily modeling technique works well. The Currant Creek and Lake Side are optimized reasonably well by a simple night time shut down screen (the approach the Company already uses for the less efficient gas-fired units.) I will discuss the approach used for the combined cycle units later in my testimony.

The proposed solution compares the daily cost of fuel, purchased power, imbalance and transmission energy costs net of sales revenue in the "with" and "without" West Valley cases.[19] To ensure that this provides the correct analysis of the GRID results, I took care to reconcile my annual sum of the daily cost results (based on GRID daily outputs) with the annual results computed "inside" the model provided in the GRID annual output reports (such as GND-1S). In the end, I was able to decompose the annual change in costs into individual daily components. Thus, I was able to ensure that daily cost variations are consistent with the total cost variations produced by the model. I also reviewed the reserve shortage outputs from GRID to ensure that there were no significant reliability impacts resulting from removal of these units.[20]

For each day, I was able to determine the impact on NVPC of including or removing specific resources. As a result, I identified the specific days when the resource (in this case West Valley) should not have been running. In this example, it can be seen that GRID is erroneously committing West Valley on New Years day, and weekends in January. My solution simply removes West Valley from operation on those days. In effect, this amounts to manually de-committing the resource. *This is nothing more than what GRID <u>should</u> be doing correctly in the first place.*

Because all of the improperly committed resources can cycle daily, there is no reason why they could not be shut down on specific days. As a result of this

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[19] These items represent the variable costs modeled in GRID in most circumstances. In cases where call options are modeled, then variable energy costs from those contracts are included as well.

[20] The same process was applied on an hourly basis for the combined cycle units.

analysis, I was able to identify the specific days when the units should not have been committed by the model.

Q. HOW WAS THE APPROACH DIFFERENT FOR THE COMBINED CYCLE PLANTS?

A. For Currant Creek and Lake Side I used an hourly cost analysis, comparing the case with and without the resources. There are many months when GRID does not show Currant Creek operating at night. In the remaining months, however, it was quite apparent that turning the plant off at night would produce lower annual NVPC. As a result, I developed a night time shut down screen (similar to that used by the Company for CT's) for Currant Creek and Lake Side. I did not attempt to optimize the screen on a daily, weekly or monthly basis. Having done so would likely produce a lower total NVPC (because it might be possible to pick up nights when it would be lower in cost to run the combined cycle plants), but would complicate the analysis somewhat. I used the same approach, but ended up with a slightly different screen for Lake Side.

Q. DISCUSS THE RESULTS OF YOUR SCREENING ANALYSIS.

A. Exhibit CCS 4.6 shows the days and hours when the units examined were removed from the GRID dispatch.

Q. WHY IS IT REASONABLE TO SIMPLY "TURN OFF" SPECIFIC UNITS AT SPECIFIC TIMES?

A. This is nothing more (or less) than what the GRID model is attempting to do (and should be doing correctly) anyway. GRID is trying to decide which days each unit should be started up, and how long they should run. GRID does not start any of these units every day. However, the model fails to determine the correct days and hours when the various units should be running. This procedure corrects that problem. In the end, I've done nothing more than the Company did with its night time shut down screen for peaking units, which has been applied now for several cases. However, I've applied it much more systematically to other units to produce a more economic dispatch of generation resources.

Q. DID YOUR ANALYSIS ELIMINATE ALL OF THE UNECONOMIC GENERATION COSTS IN GRID?

A. No. I did not eliminate all uneconomic generation costs for a number of reasons. <u>First</u>, I did not attempt to develop the most economic screens on a daily basis. To do so would have been much more time consuming. <u>Second</u>, I did not fully examine all of the units that may have been impacted by the problem. For example, I did not apply the methodology to the Gadsby units. My preliminary analysis, however, suggested these resources were not impacted by the problem to the degree that the other units were, particularly after the adjustments to the other units were made. <u>Third</u>, my approach only eliminated periods of uneconomic generation from the model. I did not attempt to determine if GRID was failing to start up units when they were otherwise should have been running, although there is some evidence that such circumstances do exist in the model. <u>Finally</u>, I sometimes departed from the most optimal daily screens to simplify the GRID inputs I developed as a concession to time constraints. I would note that such departures should not be taken as an endorsement of sub-optimal modeling of system resources.

Q. EXPLAIN THE ADJUSTMENTS YOU COMPUTED IN TABLE 1.

A. In Table 1, I present the results of GRID runs performed with these adjustments invoked on a sequential basis. Thus, the table reflects the balancing effects of these adjustments in tandem. Were they applied individually the impact would likely be greater. I also reflect the incremental start up fuel and O&M expenses resulting from daily cycling of the combined cycle units. It is my understanding that the Company already accounts for these costs using historical data in other components of its test year, rather than using GRID outputs. However, because there are more starts for the combined cycle units[21] than the Company presumed in the test year, I am reflecting them in my results.

III. CONTRACT MODELING IN GRID

Q. DOES GRID MODEL POWER CONTRACTS?

A. Yes. The Company includes the costs and energy produced by its long-term and short-term contracts in GRID, along with its thermal generation resources, in order to project normalized NVPC. I will discuss issues related to certain of PacifiCorp's long-term contracts as well as short-term contract modeling.

Call Option Contracts

Q. WHAT IS A CALL OPTION CONTRACT?

A. These are contracts that allow the Company the right to obtain additional energy on a daily basis when the market price exceeds the contract strike price. There are

[21] There are also fewer starts for West Valley in my GRID study, though I did not make any adjustment for this because the start up costs for these units are quite small.

two basic types of call option contracts used by the Company in this case: Fixed Strike Options (with a fixed strike price) and Power/Gas Spread Options (where the strike price is based on the cost of gas).

The Company has included many call option purchases in its GRID study. I have concerns about several of them: Constellation contracts 257677, 257678 and 268849; the NEBO Heat Rate Option; and UBS 268848. NEBO is the only Power/Gas Spread option contract. The others are all fixed strike price contracts.

The demand charges ($*** million in the Test Year) of these contracts are reflected in GRID; however, the contracts seldom reduce operating costs by any substantial margin based on the forward curves used in GRID. As a result, once the demand charges are included, these contracts simply add cost to the GRID study. In fact, Constellation 257678 contract *increases* NVPC in GRID even *without* removing the demand charges. Further, in GRID the NEBO and Constellation 257677 contracts increase NVPC (without removing the demand charges) in at least one month. This is, again, symptomatic of the uneconomic generation problem in GRID discussed above.

Q. PLEASE EXPLAIN.

A. Confidential Exhibit CCS 4.7 shows results of GRID runs and other information produced by the Company in the GRID database. Four of the contracts (Constellation 257677, 257678 and 268849 as well as NEBO) reflect costs related to uneconomic operation. This means that the contract should not have been dispatched in GRID on certain days. Based on my analysis, the Constellation 257678 contract should *never* have been dispatched any day during the test year.

Further, the NEBO and Constellation contracts were committed incorrectly about half the time in GRID.

Q. WERE THESE CALL OPTIONS ADDRESSED IN THE RECENT OREGON CASE, UE 191?

A. Yes. The Company proposed to remove these contracts if they failed to dispatch economically in GRID or during months when the contracts did not dispatch at all in the model. I agreed with that proposal, and it was adopted by the Oregon Commission. It is well worth noting that the same test year, CY 2008, was used in the Oregon case as is being used in this case.

Q. EXPLAIN THE PROCEDURE THE COMPANY PROPOSED IN OREGON TO ADDRESS THESE CONTRACTS.

A. In Oregon, the Company proposed to remove the contracts from GRID, if the dispatch benefits of the contracts were negative.[22] This was determined by performing GRID runs with and without the contract, while retaining contract demand charges in the "without" case. The difference between the two runs is the value of the energy (positive or negative) net of the cost of that energy. If the value was negative, the contract was removed from GRID. The Company also proposed to remove demand charges for contracts during months they did not dispatch in the model.

Q. DO YOU RECOMMEND THE COMPANY'S OREGON PROCEDURE BE ADOPTED BY THE COMMISSION IN THIS CASE?

A. I do, but with a minor modification that should ultimately benefit the Company. I believe the best approach is to first eliminate any uneconomic

[22] Note that this was a proposal made in testimony by the Company, not as part of a settlement negotiation.

generation associated with these contracts from GRID.[23] Then, if a specific contract fails to provide meaningful dispatch benefits during a month, I would remove it from the model. The primary effect of removing the contracts after uneconomic generation is removed is to eliminate the contract demand charges in months when the contract is not dispatched in the model.

This was a basic element of the Company proposal in Oregon. Under the Oregon method, however, the Company would not recover operating costs on economic operation days, if they were outweighed by days of uneconomic generation.

I believe that my slightly different approach in this case fosters a better outcome for the Company and customers because in some instances a contract may have more days of uneconomic generation than economic operation. In this manner, the Company would recover the contract operating costs, but only for the days when it makes sense to exercise the option.

Q. WHAT ARE THE RESULTS OF THIS PROPOSAL?

A. Exhibit CCS 4.7 shows the development of this adjustment. Constellation 257678 is completely removed from GRID because it never dispatches economically in the model and serves only to increase costs. The NEBO heat rate option should be removed for March, 2008 because it doesn't dispatch economically during that month. In the case of Constellation 257677, I propose to remove the contract in

[23] As will be discussed shortly, the Company did agree in the most recent Wyoming case to remove uneconomic generation associated with specific contracts, even though it later reversed its position regarding the overall application of its Oregon proposal in that case.

June and September 2008. In June, it should never be dispatched in GRID. In September, it is only economical to exercise the option for three days, producing an inconsequential benefit compared to the monthly contract demand charge.

Q. DOES THE COMPANY AGREE TO USE ITS OREGON PROCEDURE IN THIS CASE?

A. No. In response to CCS 6.25, the Company indicated it believed that similar regulatory treatment should not be applied in Utah because the Oregon approach was based on a prior case precedent in that state and that the call options provide reliability benefits to customers.

Q. IS THERE ANY COMPELLING REASON WHY THE OREGON PROCEDURE SHOULD NOT BE APPLIED IN THE CURRENT UTAH RATE CASE?

A. No. The Company's Oregon proposal provides a reasonable framework to determine the rate treatment of call option contracts. There is no reason it should not be applicable to Utah as well.

Q. IN ITS RESPONSE TO CCS 6.25 THE COMPANY STATED THAT CALL OPTIONS PROVIDE RELIABILITY BENEFITS TO CUSTOMERS. IS THIS RESPONSE ACCURATE?

A. No. Call options do not provide any reliability benefits to customers because in GRID they are not allowed to carry reserves.

Q. WHY SHOULD CALL OPTION CONTRACTS BE TREATED DIFFERENTLY FROM OTHER KINDS OF CONTRACTS?

A. Call option contracts present modeling challenges and policy issues that need to be considered. As shown above, GRID frequently fails to make economic commitment decisions for these resources. Even if that problem can be addressed, a deeper problem is that the contracts are frequently not even expected to provide overall benefits when compared against the Company's official forward price curve. Instead, the Company enters into such contracts on the basis of their option, or extrinsic value, as opposed to their intrinsic (i.e. forward curve economics) value. In short, these contracts are intended to provide price protection for the Company, but in most cases, they fail to produce ratepayer benefits in GRID. Under normalized market price conditions, many call options are not "in the money." Therefore, shareholders rather than customers are the primary beneficiaries of call options; particularly if customers bear the costs of the options, but are precluded from receiving any of the benefits under normalized ratemaking.

Q. DID THE COMPANY AGREE TO ITS OREGON PROCEDURE IN THE RECENT WYOMING RATE CASE?

A. The Company did agree to it in an initial data response answer, but later changed position. Eventually, the Company agreed to eliminate the cost of uneconomic generation associated with its call options in GRID.[24] Assuming it would at least do the same in this case, I have computed the costs of uneconomic generation in GRID. The results, shown on Exhibit CCS 4.7, support a disallowance of $922,660 on a total Company basis. This is less than my proposed adjustment of $3.59 million shown on Table 1 and is far below the $5.1 million disallowance the Company proposed (and used) in the Oregon case for the same test year.[25]

[24] See WIEC 4.45 and WIEC 4.45 First Supplemental Response in Wyoming PSC Docket No. 20000-ER-278-07. Note in this passage, I am not referring to agreements made as part of the overall settlement in that case, which did not address this issue specifically.

[25] See again, Exhibit CCS 4.4.

SMUD Contract Modeling

Q. ARE THE CALL OPTION PURCHASES DISCUSSED ABOVE THE ONLY CALL OPTIONS MODELED IN GRID?

A. No. The Company models a "call option sale" for the Sacramento Municipal Utility District. ("SMUD") I address the modeling of this contract while Mr. Hayet addresses what pricing should be use for the contract.

Q. EXPLAIN THE MODELING OF CALL OPTION SALES IN GRID.

A. For such sales GRID applies the contract energy to the highest cost hours of the year. Since the contract has an annual load factor of approximately 40%, this means GRID assumes SMUD will call the energy from the contract during the highest cost[26] 3504 hours[27] in the year. As a result, GRID assumes no energy is requested by SMUD during the low cost months from March to June. Based on historical data, however, this assumption is flawed. In fact, the Company's assumptions amount to determining the "worst case scenario" when it comes to the SMUD contract.

Q. PLEASE EXPLAIN.

A. The table below shows the actual monthly distribution of SMUD energy for the four-year period (2003-2007) as compared to the GRID result.[28] It is quite apparent that SMUD takes energy at substantially different times than predicted by GRID. This is not surprising since SMUD is attempting to optimize the use of the contract for its own purposes rather than using the contract to impose the maximum amount of cost on PacifiCorp (as is assumed in GRID). For whatever

[26] Based on COB market prices.
[27] 8760*.4 = 3504.
[28] Source: CCS 13.8.

reasons, SMUD is not using the contract in the "maximum cost" manner assumed by the Company in GRID. The historical data presented in the table below shows that SMUD takes energy associated with the contract in a much lower cost pattern than assumed in GRID.

Table 2

SMUD LTF Contract: Actual vs. GRID MWH

Month	4 Yr. Avg	GRID	2001 Case
1	50,352	39,600	20,538
2	46,325	21,300	7,704
3	31,371	-	19,973
4	30,754	-	27,327
5	30,039	-	23,674
6	35,056	-	17,123
7	44,879	35,400	28,378
8	34,914	52,800	27,941
9	0	45,600	72,004
10	18,349	46,800	33,286
11	17,696	46,100	31,918
12	10,665	63,800	40,533
Total	350,400	351,400	350,400

Q. HOW DID YOU ADDRESS THIS PROBLEM?

A. I developed the monthly energy for SMUD for the Test Year based on the four-year average from 2003 through 2007. I then assumed that on a monthly basis, SMUD would optimize the contract based on maximizing COB market revenues. This approach is likely to still overstate the cost of serving SMUD, since they may not do a "maximum cost" dispatch on a monthly basis any more than they do on an annual basis. Nonetheless, this adjustment provides a reasonable means of rectifying this problem. This adjustment is shown on Table 1.

Q. ARE THERE ANY OTHER ISSUES RELATED TO SMUD MODELING?

A. Yes, there are two additional issues. First, in the 2001 case where the SMUD pricing was last decided by the Utah Commission, the Company also assumed a less costly distribution of sales to SMUD than is currently assumed by the Company. Should the Commission reject Mr. Hayet's proposal to re-price SMUD (and instead retain the 2001 price), at a minimum it should recognize that the $37/MWh price and the 2001 usage pattern case go hand in hand. In that case the distribution shown on Table 2 above should be used. This would result in a reduction of $1.426 million on a Total Company basis.

Second, the SMUD contract limits annual firm deliveries to 350,400[29] MWh, making no exception for leap year. However, GRID includes sales of 351,400 because it allows extra energy to be delivered due to the extra day included in 2008. This additional adjustment is shown on Table 1.

Hermiston Losses

Q. PLEASE EXPLAIN THE HERMISTON LOSS ADJUSTMENT IN GRID.

A. The Company wheels Hermiston power over the Bonneville Power Administration ("BPA") transmission system. As a result, the Company imposes losses on the BPA system that it must later return to BPA. The Company models these losses as a zero revenue sale in GRID.

Q. DO YOU AGREE WITH THE LEVEL OF LOSSES ASSUMED IN GRID?

A. No. The workpapers computing the losses included in GRID (See MDR 2.63.-1) is premised on an assumed loss level of 75,000 MWh per year allegedly occurring

[29] The SMUD contract also provides for additional provisional energy, which is later returned to the Company. On a normalized, annual, basis, there is no additional energy available to SMUD from this aspect of the contract.

during the period October 1999 to January, 2005. We inquired about this figure during the on-site interviews and in CCS data request 15.2. In neither case could the Company explain the source of the figure used and indicated only that it was an estimate. Exhibit CCS 4.8 shows excerpts from the Company workpapers and my correction to it.

Q. PLEASE EXPLAIN YOUR CORRECTION TO THE LEVEL OF HERMISTON LOSSES?

A. No. In discovery in the current Wyoming PCAM case I obtained a letter from BPA to PacifiCorp showing the monthly losses during this period. Exhibit CCS 4.9 shows a copy of a letter from BPA to PacifiCorp indicating the actual losses that occurred during the period in question. My calculation shows that the correct level of losses for the period was only 55,000 MWh per year. Reducing the losses in GRID to the appropriate level produces the adjustment shown on Table 1.

SMUD Pricing, QF Contracts and Wind Resources

Q. PLEASE DISCUSS THE OTHER ADJUSTMENTS SHOWN ON TABLE 1 FOR SMUD PRICING AND QF CONTRACTS.

A. I have incorporated SMUD pricing and QF contract adjustments sponsored by Mr. Hayet in his testimony into Table 1.

Arbitrage and Trading Profits in GRID

Q. EXPLAIN THE DIFFERENCE BETWEEN BALANCING, ARBITRAGE AND TRADING AS REGARDS SHORT-TERM FIRM TRANSACTIONS.

A. Balancing is the process of matching supply and demand. The Company constantly engages in short-term firm transactions to effectuate a more optimal balancing of the system. The goal of balancing is to match supply and demand and minimize costs, but not necessarily to make profits on transactions.

Arbitrage occurs when the Company is able to take advantage of price differences between counterparties.[30] Profit generation is the goal of arbitrage and when the right opportunities are present, it is not a risky endeavor.

Trading is when the Company takes a position (long or short) at one price, and then closes that position later at a (hopefully) better price.[31] The goal of trading is also to generate profits; however, it involves an element of risk because expected price changes may or may not occur. Over the period 2004-2007, 87% of the Company's short term transactions were related to balancing while 13% were for arbitrage or trading purposes.[32]

Q. HAS THE COMPANY INCLUDED ANY ARBITRAGE OR TRADING PROFTS IN GRID STF TRANSACTIONS?

A. The Company has included some arbitrage and trading profits in the short-term firm (STF) transactions it modeled in GRID. My analysis of the 2nd Supplemental Response to CCS 2.49 shows the Company has included approximately $205,000 in STF arbitrage profits and $579,000 in STF trading profits in GRID. These levels, however, fall far short of historical averages, because the Company only included STF transactions that it had arranged by the time of the December 2007 filing. Many more transactions will actually occur during the test year, based on history.

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30 See attachment to CCS 2.40-1, pages 133-134.

31 Id., page 134.

32 1st Supplemental Response to CCS 2.48

Q. HOW SHOULD GRID RESULTS BE MODIFIED TO REFLECT STF ARBITRAGE AND TRADING PROFITS?

A. I recommend imputation of the four-year average for STF arbitrage and trading profits. Over the four-year period 2004-2007, the Company's arbitrage and trading profits averaged approximately $4.4 million. Exhibit CCS 4.10 shows the development of this adjustment based on the responses to CCS 2.48 and CCS 2.49. I recommend the STF profits currently included in GRID be reversed and these normalized profits be imputed instead. The impact of this adjustment is shown on Table 1.

Q. HAVE OTHER COMMISSIONS ADOPTED THIS ADJUSTMENT?

A. Yes. In the most recent Oregon NVPC update case (UE 191) the OPUC stated:

> Thus, we accept Staff's premise that the GRID model systematically understates the extent of Pacific Power's wholesale market activities. From that premise Staff infers that Pacific Power receives a systematic positive return on its net short-term wholesale transactions that are not included in the GRID runs. Staff attributes that return to Pacific Power's ability to leverage the flexibility of its diversified system.
>
> * * *
>
> The remaining 13 percent of Pacific Power's short-term wholesale transactions are properly attributed to Pacific Power's arbitrage and wholesale trading activities. The Company calculated that the Oregon allocated margins on such activities averaged $0.8 million annually (from 2003 through 2006). There is no evidence that those results are included in the GRID model results. However, we conclude that such revenues are properly considered in the calculation of NVPC and the model results should be adjusted as necessary to incorporate those revenues. (OPUC Docket No. UE 191, Order 07-446 pages 10-11.)

IV. PLANNED OUTAGE SCHEDULE

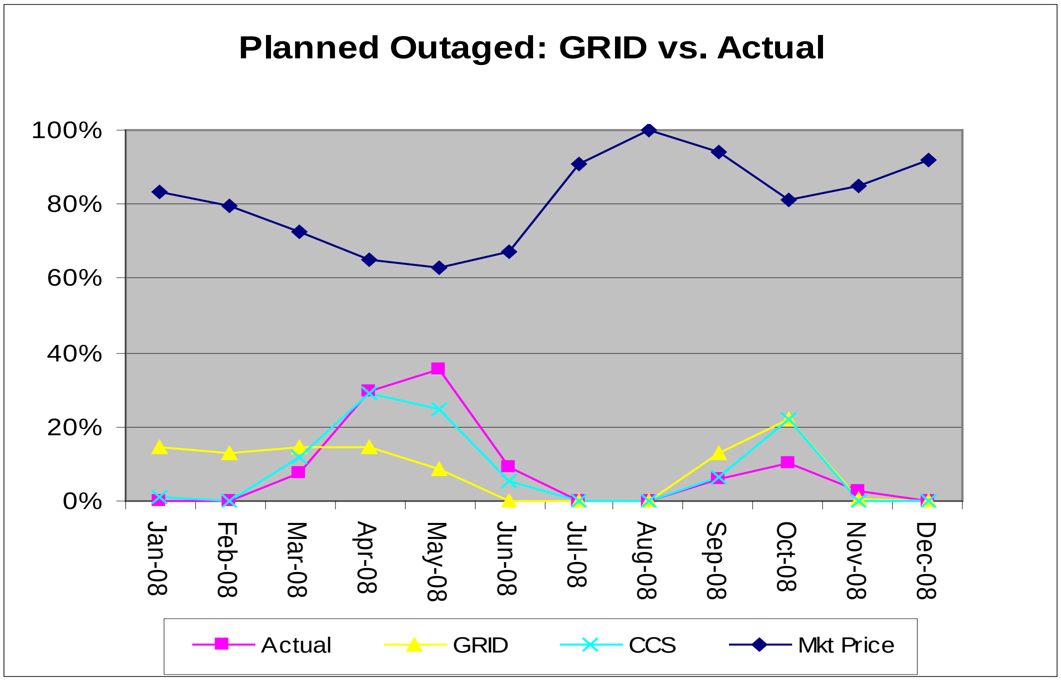
Q. WHAT ARE PLANNED OUTAGES?

A. Planned outages represent times where generators are taken out of service for routine scheduled repairs and maintenance. Plants are typically taken down once per year for scheduled work. During the on-site interviews we conducted on February 15, 2008 we learned this work is normally scheduled in the spring when demand and market prices are at their lowest levels.

Q. DOES THE COMPANY USE THE ACTUAL GENERATOR MAINTENANCE SCHEDULE FOR THE TEST YEAR IN GRID?

A. No. The Company uses a "normalized" maintenance schedule, with outage durations based on a four-year average. Given that the planned maintenance schedule can be changed in response to forced outages and other events, and the four-year average outage rate may not coincide with actual outages planned for the test year, use of a normalized maintenance schedule is reasonable. However, I do not believe that the schedule actually used in GRID is a reasonable representation of a normalized maintenance schedule. The figure below illustrates the problems with the planned outage schedule assumed in GRID.

Figure 3



Q. PLEASE EXPLAIN THIS FIGURE.

A. This graph shows the percentage of coal-fired scheduled outage energy[33] for each month of the calendar year due to planned outages based on the 48-month period ended June 30, 2007. For example, during the 48 month period, nearly 40% of annual scheduled outage energy occurred in May. Superimposed on the chart is an index showing the market price assumptions used in GRID. Also included are the comparable figures for the test year based on the GRID inputs and Committee's proposed planned outage schedule.

It is apparent from the chart that actual planned outages have traditionally been scheduled to coincide with the low market price periods in the spring and fall. The chart shows April, May and June have the lowest market prices, and the

[33] This would be the amount of coal-fired energy the Company would need to replace in order to make up the generation lost due to planned outages.

Company traditionally has performed most of its maintenance (nearly 75%) during these months.

In contrast, the Company assumes in GRID that more outages will occur in the winter months and in September and October. In GRID, it is assumed coal plants will have 15% of scheduled outage energy in January and 13% in February. It is notable that, during the four-year historical period, the Company did not schedule *any* significant coal plant outages in January or February. Nor does it have any plans to actually do so in 2008 or 2009. The Company further assumes in GRID that about 13% of coal planned outage energy will occur in September and that 22% of planned coal outage energy will occur in October. Both figures substantially exceed the actual historical outages as well (10% or less) for those months.

In all these cases, the GRID planned outages are assumed to occur during periods when higher market prices prevail, as compared to actual and expected planned outage schedules.

Q. DID YOU ALSO EXAMINE THE PLANNED OUTAGES ACTUALLY SCHEDULED FOR THE 2008 TEST YEAR?

A. Yes. The confidential response to CCS 2.38 provided both the 2008 and 2009 planned outage schedule. Since the answer is confidential, I didn't include it in the chart above. However, a careful review of the response to CCS 2.38 shows it follows a pattern comparable to those used during the four-year period. Thus, any conclusions regarding outage schedules are reinforced by the outages presently planned for the next two years.

Q. WHY DO YOU USE THE FOUR YEARS ENDED JUNE 30, 2007 AS THE REFERENCE POINT FOR ACTUAL HISTORICAL OUTAGES?

A. The duration of planned outages in GRID is based on this four-year period. Therefore, the Company considers this period to define normalized results. For this reason it is a useful reference point to compare to the GRID planned outage schedule. I also have data on all PacifiCorp generator outages (planned and unplanned) going back to 1979. These data follow essentially the same pattern as discussed for the four-year period.

Q. HOW DOES THE COMPANY DEVELOP THE PLANNED OUTAGE SCHEDULE FOR GRID?

A. The approach actually used in GRID is an arbitrary and essentially mechanical process that and does not appear to be based on historical or expected outage schedules, market price curves or other scheduling considerations. The response to MDR2.57-1 provides the workpapers used to develop the schedule for planned outage in GRID. Included in those workpapers is a page called “Considerations” listing factors allegedly used by the Company in developing the planned outage schedule in GRID. These considerations are listed below:

Work crew availability - long lead times required for contractors generally can only work on one unit per plant hard to get workers during hunting season

Capacity on outage - in addition to system total, watch balance in transmission areas

Peak loads / High prices - avoid early July to mid September and late November to mid February

Sales in transmission constraint areas - for Cholla and UPL plants, avoid scheduling when delivering the APS Exchange (15 May to 15 September)

Open design / High altitude - avoid scheduling in cold weather for plants like Wyodak, Hunter, …

Single unit per plant - allow for delay in startup when scheduling another unit at same plant (expect when scheduling "normalized", which case schedule them back to back.)

Co-owner / Co-generator - for Bridger, avoid IPC fall hydro season work around schedule for plants like Craig, Hayden, …coordinate with Fort James, GSLM, …

Non owned plants in control area - include plants like River Road, Bonanza, DG&T Hunter share in capacity outage totals don't schedule Hermiston at the same time as River Road

Unit contingent purchases include unit contingent purchases from plants like Sunnyside, San Juan Unit 4 in capacity outage totals

Weekend outages generally begin on Saturday or Sundays so parts are cooled by Monday (see above exception for "normalized")

Q. ARE THESE REASONABLE CONSIDERATIONS FOR THE SCHEDULING OF PLANNED OUTAGES?

A. Yes. On February 15, 2008 we discussed the process used to develop actual plant outage schedules with Mr. Mark Mansfield, PacifiCorp's VP of Operations Support and other Company personnel. Regarding the development of plant outage schedules, some of the above considerations were mentioned by the Company representatives. It should be noted, however, that the first thing mentioned in this meeting was that outages were scheduled in the spring (mid March to late May) to take advantage of low cost power in the market. It was also discussed that a second, though less preferable, window for outages occurs in the fall. As the historical data shown above indicates, the Company strongly prefers to actually schedule outages in the spring.

Q. HOW DOES THE COMPANY ACTUALLY APPLY THESE FACTORS IN DEVELOPING THE NORMALIZED OUTAGE SCHEDULE FOR GRID?

A. The actual application in GRID differs substantially from the items listed above. In the response to CCS 6.15 the nexus between these factors and the GRID outage schedule was explained:

Response to CCS 6.15:

The tab "Considerations" has a list of items that were considered when developing the planned outages schedule for ratemaking purposes. As suggested by the title on the page, "**General** considerations for scheduling annual maintenance," *the list provides guidelines rather than scheduling requirements.*[34]

Work crew availability – Unit planned outages are not stacked, Units are scheduled sequentially.

Capacity on outage – the tab "PO Daily" was used to review planned outages by transmission areas.

Peak loads / High prices - Maintenance is avoided during the summer months and *during some winter months.*[35]

Open design / High altitude - *Wyodak is scheduled in October*.[36]

Single unit per plant - Units are scheduled sequentially.

Co-owner / Co-generator - Bridger is scheduled in the spring.

Non owned plants in control area – Clark River Road, Bonanza and DG&T's portion of Hunter are included in scheduling analysis totals. Clark River Road and Bonanza contracts have expired.

Unit contingent purchases – Sunnyside and San Juan Unit 4 are included in schedule analysis totals.

Weekend – Units are scheduled sequentially.

It should be rather obvious that many of the criteria actually used in GRID are substantially simplified from the considerations set forth in the workpapers attendant to MDR 2.57-1.

Q. DOES THE COMPANY ACTUALLY CHECK TO DETERMINE WHETHER THE GRID OUTAGE SCHEDULE IS CONSISTENT WITH THESE GUIDELINES OR WITH ACTUAL PRACTICE?

A. It does not appear that the Company attempts to reconcile the GRID outage schedule with these guidelines or actual (and expected) plant outage schedules. For instance, several coal units have outages scheduled in January and February

[34] Italics added.
[35] Italics added. In reality the only winter month when outages are avoided was December.
[36] Italics added.

in GRID. This includes units at Cholla, Craig, Hayden, Hunter and Naughton. In the answer to CCS 6.15 discussed above, the Company admits that the requirement related to avoiding outages in cold weather for open design/high altitude plants was limited to scheduling Wyodak in October.[37] This is a highly questionable simplification because in CCS 6.16 the Company acknowledged that all of its coal plants are "high altitude/open design" resources. Thus, compliance with the actual practices and stated guidelines would clearly exclude scheduling of outages for any of the coal plants in the winter months.

Q. DID YOU ASK THE COMPANY WHY IT APPARENTLY VIOLATED ITS OWN CRITERIA IN ESTABLISHING THE NORMALIZED OUTAGE SCHEDULE FOR GRID?

A. Yes. In an attempt to allow the Company to explain why the GRID outage schedule included these winter outages for coal plants we explored the matter in Data Request CCS 5.1:

CCS Data Request 5.1

NPC GRID Modeling. MDR-2.57 contains a worksheet that lists considerations related to planned outage scheduling. It states the cold weather/high load months are to be avoided for planned outages for Hunter, Wyodak and other plants, and that the period late November through mid February are to be avoided. However, the GRID data base shows planned outages for Cholla, Craig, Hayden, Hunter and Naughton in the months of January and February 2009. Further, during the four-year period ended June 2007 none of these units actually had outages scheduled in January or February. Given the criteria delineated in the worksheet provided as part of MDR-2.57, does the Company believe that the normalized outage schedule included in the GRID database is reasonable?

Response to CCS Data Request 5.1

Yes. For normalized ratemaking purposes, GRID is required to schedule planned outages for all plants during a one year period. To do otherwise would result in planned outages at certain generating units being ignored in the determination of

[37] This is by itself unrealistic because during the four year period only 4% of energy lost due to Wyodak planned outages occurred in the fall.

normalized power costs. In actual practice, planned outages can be staggered across multiple years; however this cannot be reflected in GRID without skewing normalized power costs.

In developing the normalized outage schedule for GRID, the Company ensures that (1) the months of July and August have no scheduled maintenance; (2) the overlapping of unit outages is minimized; and, (3) outage periods include as much time over the weekend as is possible given the length of the outages defined by the 48-month period.

Q. IS THIS REASONABLE?

A. No. First, I examined the planned outage schedules used in GRID in the most recent Wyoming and Oregon cases, as well as the prior Utah case. In none of these cases did the Company find it necessary to schedule planned outages for coal-fired power plants in January in GRID.[38] Consequently, it is difficult to understand why the Company now believes it would "skew" normalized power cost results if it did not schedule planned outages in January.

Second, the answer makes little sense numerically. Major outages for generators don't occur every year and certainly there will be fewer numbers of units on outage during a specific year than would be the case in a normalized test year. However, this does not mean that normalized scheduling of outages must extend into the high cost cold weather months. For example, consider a plant with four single units, such as Bridger. A typical outage schedule might show each of the four units on outage for four weeks once every four years. On a normalized basis this would amount to four one-week outages for a single test year. If a single unit of the plant normally goes on outage for four weeks in May, for example, there is no reason why the four one-week outages could not be

[38] The Company did schedule some planned outages for coal plants in February which I disagreed with as well. I filed testimony addressing this problem in the recent Wyoming case.

modeled in GRID for May as well. The Company's argument about "skewing" the results is clearly unfounded.

Q. DO ANY OF THE OTHER SCHEDULING CRITERIA DISCUSSED ABOVE PROVIDE JUSTIFICATION FOR THE GRID OUTAGE SCHEDULE?

A. No. This topic was explored in depth in discovery. In CCS 6.17 we inquired as to whether the Company performs any analysis to determine if the criteria related to "system totals" or "transmission area balances" was satisfied. The Company responded "There is no analysis of whether they were met."

In CCS 6.18 we inquired regarding how the Company determined whether the criteria related to avoidance of outages in late November to mid-February was satisfied. Again the Company responded that "There was no analysis of whether they were met."

In CCS 6.19 we inquired regarding the work crew availability limitation issue. Again, the response was that "There was no analysis of whether they were met."

Based on my analysis of this issue, I concluded that the Company has devised a purely mechanical process to develop an outage schedule in GRID that is unrelated to the scheduling considerations cited by the Company. Were GRID to actually apply the criteria discussed above, it would produce a schedule that looks much more like the actual schedule, and result in lower NVPC.

Q. PLEASE EXPLAIN THE TABLE BELOW.

A. This table is based on a correlation analysis I performed and provides the correlation coefficients between the individual variables related to planned outages. The correlation coefficient (“*r”)* is a statistical measure of how closely two variables track each other. A high correlation means two variables move nearly in lock-step, while a low correlation indicates that they move independently of each other. A negative correlation means two variables move in opposite directions, such as historical outages and market prices.

This table shows that the actual historical schedule is negatively correlated with market prices (*r*=-77% for the four-year actual.) This demonstrates that the Company does attempt to minimize cost by scheduling outages during low market price periods, and by avoiding planned outages when market prices are high.

The GRID “normalized” outage schedule, however, has only a weak negative correlation to market prices (*r*=-32%) and a weak positive correlation to the actual four year historical schedule (*r*=29%.) This demonstrates that the GRID outage schedule methodology deviates from a credible normalization process and bears almost no relationship to actual practice, historical data or market prices.

<u>Table 3: Statistical Correlations</u>

Correlation	Actual	GRID – TY	CCS	Mkt Price
Actual (4 YR Period)	100%	29%	90%	-77%
Test Year (GRID)	29%	100%	58%	-32%
CCS	90%	58%	100%	-69%
Market Price	-77%	-32%	-69%	100%

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE PLANNED OUTAGE SCHEDULE ISSUE?

A. I recommend the Commission adopt my adjustment related to a more realistic planned outage schedule. My adjustment shifts the winter-spring coal plant outages forward to better match historical and planned outages. I also moved the

Colstrip outages (assumed in GRID to take place in the fall) to the spring. I did so because Colstrip planned outages have not traditionally occurred in fall months. This proposed schedule has a much better correlation with the four-year actual outages (*r*=90%). It also demonstrates a much more reasonable negative correlation to market prices (*r*=-69%). As a result, the NVPC using this more realistic schedule is lower than the Company's result. As can be seen from the earlier graph, this revised schedule still places more outage energy in the fall than have actual schedules. Further, no single month has an excessive amount of maintenance planned. Because this pattern is more consistent with the actual planned and historical schedules used, it is clearly a feasible solution and it produces far more optimal results than the suboptimal schedule assumed by the Company. The results of this adjustment are shown on Table 1.

Q. IN DEVELOPING YOUR PROPOSED OUTAGE SCHEDULE HOW DID YOU APPROACH THE CRITERIA LISTED ABOVE?

A. I used the schedule already in GRID as the starting point. I also avoided overlaps of outages at a single plant, attempted to schedule outages (where possible) to start on a weekend, and I developed graphs to show the number of units and MW of capacity on outage each week during the year. Naturally, I avoided the winter months, and tried to maximize spring outages without putting too much capacity or too many units on outage at the same time.

In developing this analysis, it became rather apparent that the Company really ignored the problem of outage overlaps in its scheduling methodology. For example, in one week during October 2008, the Company showed 1200 MW and as many as six units on outage. This is substantially higher than actual plant outage history, which averaged no more than 400 MW and less than 2 units on average for the same period. Likewise, in January and February, the Company scheduled 3-6 units on outage representing roughly 600 MW of capacity. In the four-year historical period, the Company normally scheduled only a few gas units for outage during those months. In contrast, the Company scheduled more capacity and more units on outage in January in GRID than it did in May. This analysis demonstrates that the amount of capacity and number of units in my proposed schedule follow historical patterns rather well, while the Company's schedule does not.

Q. IS THERE AN ALTERNATIVE METHOD THE COMMISSION MAY WISH TO CONSIDER FOR MODELING OF PLANNED OUTAGES?

A. Yes. Another alternative would be to simply reflect the actual history of planned outages in the computation of forced outage rates. While forced and planned outages are fundamentally different, in GRID modeling, they both result in removal of a specific amount of capacity at a specific time from the model. Therefore, there is no technical reason why they need to be modeled in different ways within GRID. This approach would result in each unit having the correct amount of scheduled outage energy on a monthly basis. While I object to the use of monthly <u>unplanned</u> outage rates because there is no underlying basis for using them (to be discussed shortly), for planned outages there definitely is a systematic monthly and seasonal pattern.[39] There is no reason why this method would not produce realistic results. In particular, if the Commission retains the use of monthly unplanned outage rates, it should be consistent and adopt this adjustment

[39] The Company acknowledged as much in it response to CCS 21.1.

as well. However, the Commission need not adopt monthly unplanned outage rates in order to adopt this adjustment. Use of this approach would reduce NVPC by $10.6 million, which is comparable to my results using the revised outage schedule. This analysis further demonstrates the reasonableness of my adjustment to the Company's planned outage schedule.

V. GRID HYDRO MODELING

Q. DID YOU REVIEW THE GRID HYDRO INPUT DATA SOURCES?

A. Yes. As part of my review of the VISTA modeling technique (to be discussed shortly), I requested the historical data underlying the actual GRID inputs and the most recent forty years of consistent hydro data (CCS 2.3 and CCS 2.4). I also obtained a forty-year hydro weekly input file for GRID for the test year ended June 30, 2008 from the recently filed Washington case. This investigation showed problems related to the inconsistencies in the data periods used for different resources.

The Company's storage resource inputs were based on the three different time periods: 1959-2003 for Lewis River resources; 1964-2003 for Klamath River resources; and 1962 to 2003 for the Umpqua River projects. Run of river resources were based on yet another forty-year period: 1967 through 2006. Mid-Columbia resources were based on a sixty-year period from 1928 through 1988. A consistent forty-year data set for all resources for the period 1964 through 2003 was provided in the response to CCS 2.3. This data was selected for the same period of time as the Company uses in its Washington state filings.

Q. WHAT IS THE PROBLEM WITH USING THE INCONSISTENT DATA?

A. The use of varying time periods tends to understate the amount of hydro energy that would be available to serve load when compared to the more conventional multiple water year analysis the Company used in prior cases. It is hard to justify use of a sixty-year period for some hydro resources and forty to forty-five for others based on differing time periods.

Q. HAS PACIFICORP CHANGED ITS HYDRO MODELING METHOD IN RECENT UTAH RATE CASES?

A. Yes. The last Utah rate case where NVPC was fully litigated was Docket No.01-035-01. In that case (and all prior cases), the Company used a traditional multiple water year modeling methodology. In the first case involving use of the GRID model, Docket No. 03-2035-02, the Company continued to use conventional multiple water year modeling.

In the 2004 case, Docket No. 04-035-42, the Company significantly changed its hydro modeling, and began relying upon a new model called VISTA. The same approach has been used in all subsequent cases, though none of those cases were litigated past the stage of the Company filing rebuttal testimony as was the case in 2004. In all of those cases disputes surrounding use of these new modeling techniques occurred, but were not resolved. Consequently, the Commission should recognize that this is a case of first impression regarding GRID hydro modeling.

Q. HOW DOES VISTA DIFFER FROM THE HISTORICAL MULTIPLE WATER YEAR MODELING APPROACH?

A. Traditionally the Company used multiple water years (normally forty to sixty years) to simulate normalized net power costs.[40] VISTA does not rely on these traditional water year simulations. Rather in the current implementation, VISTA produces a set of three "exceedence"[41] levels representing Wet, Median and Dry ("W-M-D") hydro conditions. These scenarios are intended to represent exceedence levels corresponding to the 25th, 50th, and 75th percentiles. (Widmer/Duval Direct, page 24). The VISTA model develops the hydro generation scenarios for each resource based on historical stream flows. As discussed above, the data used by the Company does not correspond to the same historical periods for all resources.

Q. DO YOU HAVE ANY CONCERNS ABOUT THIS APPROACH?

A. Yes. The method produces a numerically reasonable result for median hydro conditions, but greatly overstates the likelihood of extreme (wet or dry) hydro conditions. In particular, the Company's approach to estimating the exceedence levels is incorrect and is based on two fallacies.

The first fallacy is that the Company assumes that generation from all of its hydro resources are perfectly correlated across river systems and throughout the year. This means that all of the hydro resources are assumed to experience their wet, median, and dry conditions simultaneously. Indeed, it is assumed that generation from all hydro resources moves in lockstep. For example, the Company assumed that if the western system hydro resources were having a "dry" year, the same would be true for the Mid-Columbia and even the eastern hydro

[40] The Company still relies on forty water year modeling in Washington state rate cases.
[41] This is a term coined by the Company, and as far as I know, is not used anywhere else.

resources. Consequently, the “dry” (25th percentile) case assumes that all five major river systems will experience a drought. The same is true for the “median” and “wet” hydro scenarios.

Even more problematic is the second fallacy, concerning the manner in which the Company constructed various scenarios on an annual basis. In the “dry” cases, it was assumed that every generator experienced “dry” conditions every single week of the year. The same is true for “median” and “wet” cases. This process produces highly unrealistic results and overstates the likelihood of extreme conditions, because the “dry” and “wet” scenarios will not happen for all river systems at the same time and certainly will not all occur every single week of the year.

Q. COULD YOU PROVIDE A SIMPLE EXAMPLE TO ILLUSTRATE THE FIRST FALLACY DISCUSSED ABOVE?

A. Yes. Consider a simple game involving six throws of a pair of fair dice. One can easily compute the expected value outcome of a throw, by assuming each side of a single die would have chance of one in six of occurring. One would compute a probability level of 16.66% for a score of one on a single die; 33.33% for a score of two or less; 50% for 3 or less; 66.66% for four or less; 83.33% for five or less; and 100% for six or less.

In the VISTA method, for a roll of a pair of dice, it is equivalent to assuming that the two dice (like two river systems) are perfectly correlated. This would imply a probability of 16.66% to roll a pair of ones; 33.33% for a pair of twos or a pair of ones; 50% for a pair of threes, twos or ones and so on. It should be fairly obvious that probability levels computed under the VISTA assumption are completely unrealistic. Indeed, simple probability theory shows that the chances of rolling a pair of any number is (1/6)*(1/6) or 1/36. If the river systems, like individual dice, are independent, the VISTA methodology systematically miscalculates the probabilities, even if we assume the underlying data is perfectly accurate. My analysis of correlation data for the various river systems has shown that the assumption of perfect correlation is unfounded and unrealistic.[42]

Q. WHAT IS THE FUNDAMENTAL PROBLEM WITH THE VISTA MODEL?

A. The most substantial problem is that VISTA overstates the likelihood of extreme events, whether drought or flood conditions. Returning to the dice example, the probability of a pair of ones (or a pair of sixes) is only 1 in 36. In VISTA it is assumed the probability is 1 in 6. This means that VISTA would be overstating the probability of an extreme event (in this case, the roll of a pair of ones or sixes.) However, VISTA ignores the many more likely scenarios where the two dice have different face values (e.g., a one and a six).

Q. IS THERE ANOTHER EASY EXAMPLE THAT ILLUSTRATES WHY THE COMPANY'S ASSUMPTION THAT WET OR DRY CONDITIONS WILL OCCUR EACH WEEK OF THE YEAR (THE SECOND FALLACY) IS WRONG?

A. Yes. Assume one was trying to develop a wet rainfall scenario for Salt Lake City. While Salt Lake City is regarded as being rather dry, it does average 90 days per year of measurable rainfall and 5-10 days per month. If one were to look at all of the years of recorded history, it would almost certainly be possible to find at least one year when it rained in Salt Lake City for any specific week of the year. Put

[42] Shortly, I will show that the Company has already acknowledged as much in earlier cases.

another way, it is quite unlikely that there is a single week, even in dry Salt Lake City, where it has never rained in recorded history. Likewise, it is also reasonable to assume that over many years of history, one could always find a year where it did not rain in a specific week. It is very unlikely that over many years, there is not a single week where it has rained every single year.

Q. HOW DOES THIS RELATE TO THE COMPANY'S SELECTION OF A WET (OR DRY) HYDRO SCENARIO?

A. Unfortunately, the Company's approach to selecting a wet scenario would be akin to assuming that it rains every week of the year in the wet case, because there was always some year in history when it did rain during that week in Salt Lake City. Likewise, the Company's approach to the dry scenario is akin to assuming that it never rains in Salt Lake City in the dry case (because one can always find at least one year where it didn't rain during any particular week).

The logic behind the Company's wet case, would suggest that the wet scenario for Salt Lake City, would be a year where it rains every single week. This is because the Company would construct its wet scenario by combining the results for 52 wet weeks (just as it constructed the wet hydro case from 52 wet weeks – the second fallacy.) I submit that a year where it rains every week is something that has never been recorded in Salt Lake City. Likewise, the Company's logic would suggest a dry scenario for Salt Lake City, where it never rained even during a single week.

The basic problem here is the assumption that a wet (or dry) case should be constructed by accumulating individual wet (or dry) weeks while ignoring the annual pattern of wet and dry conditions. The Company constructs its wet (or dry) hydro scenarios assuming that each <u>week</u> of the year experiences wet (or dry) hydro conditions. In reality, it never happens that way. Wet years are those where there are many rainy days or weeks, but not cases where it rains every single week. Even in the wettest years in history, it likely did not rain every single week. The same is true in the dry case. However, the Company's approach ignores common sense and greatly exaggerates the severity of the wet and dry cases. This makes them very unlikely outcomes. However, in GRID, the Company assumes the wet and dry cases occur once every three years. The reality is much different. These scenarios may occur, but only about once every forty years.

Q. DO YOU HAVE ANY EVIDENCE THAT DEMONSTRATES THE VISTA DATA USED IN GRID OVERSTATES THE LIKELIHOOD OF EXTREME EVENTS?

A**.** Yes. Exhibit CCS 4.11 shows a comparison of the exceedence levels for the Wet, Median and Dry ("W-M-D") cases based on the filed VISTA data in GRID and W-M-D cases based on the VISTA methodology applied to the 40 water years of data (1964 to 2003) provided in CCS 2.3 When compared to the actual 40 water year data, it is apparent the VISTA methodology applied to the GRID input really produces 1%, 48%, and 98% scenarios, rather than the 25%, 50%, and 75% scenarios the Company believes is produced. In other words, the Company greatly exaggerates the probability of the extreme (wet and dry) occurrences, while understating energy in the median case as well.

Q. CAN YOU DEMONSTRATE THAT THE USE OF THE WET, MEDIAN AND DRY SCENARIOS IN GRID OVERSTATES NVPC?

A. Yes. In the current Washington case, the Company filed a forty-year hydro data set for the June 30, 2008 test year. This is consistent with the Mid-Period test year prepared by the Company as part of its original filing. A run of the Washington forty-year hydro data in the Utah version of GRID produced NVPC approximately $1 million less than the data used by the Company. Likewise, a run on the Washington version of the GRID model using the erroneous Wet, Median and Dry scenarios filed in this case for the same test year produced NVPC approximately $1 million higher than the forty-year hydro data. These results actually underestimate the bias in the GRID data used in this case because the forward curves used to optimize the GRID dispatch differed in the two proceedings. Optimizing the hydro dispatch for the proper forward curves would further lower NVPC.[43]

Q. WHAT IS YOUR RECOMMENDATION REGARDING THIS ISSUE?

A. My recommendations on this issue are threefold:

(1) At a minimum, the Commission should simply use the median hydro scenario in this case. While I do not agree with the method used to compute the median hydro case, or the time periods selected, this scenario does produce approximately the correct amount of energy compared to a proper forty-year analysis using consistent data. Moreover, as I discuss below, the Company has agreed that a median hydro scenario is a reasonable approach in a recent Oregon case.

[43] In the recent Wyoming case the Company failed to optimize the hydro dispatch in VISTA for the then current forward curve. Optimizing the hydro for the correct forward curve reduced NVPC $542 thousand.

(2) The Commission should eliminate the bias or deficiencies in the Company's modeling by changing the weights for the Wet, Median and Dry cases according to those shown on Exhibit CCS 4.11. I developed these weights using a histogram based on the forty water year data and determined which of three blocks (based on the Wet, Median and Dry cases) each single year would fall into. The results are then used as weights for each of the three GRID scenarios. This produces the hydro adjustment shown in Table 1.

(3) The Commission should require the Company to use a consistent time period for development of the hydro data and to address these deficiencies in its modeling approach in the Company's next rate case filing.

Q. HAVE SOME OF THESE ISSUES RELATING TO PROPER HYDRO MODELING BEEN ADDRESSED IN PRIOR CASES IN OTHER STATES?

A. Yes. In the first case where the VISTA method was applied (Docket No. 04-035-42), the Company originally proposed to use nineteen exceedence levels (5% through 95% in 5% increments.) I pointed out the problems related to this modeling and Mr. Widmer agreed that my criticisms had merit and abandoned the use of multiple exceedence levels in favor of the simple median case:

"The observation concerning the VISTA exceedence levels has some merit. . . To address this issue the Company proposes to abandon normalizing hydro availability with 19 exceedence levels in favor of using just the medium (50%) exceedence level." (UPSC Docket 04-035-42, Widmer Rebuttal, Page 26.)

In subsequent cases, the Company started using the three part (W-M-D) solution. However, the Company has simply replaced nineteen bad estimates with three bad estimates. This does not make the final results any more valid.

In the most recent Oregon case (UE 191), Mr. Widmer again acknowledged that the various river systems underlying the hydro resources were not perfectly correlated, as assumed by VISTA, and strongly suggested again that use of the median hydro was an appropriate solution to the problem. (OPUC Docket No. UE 191, Widmer rebuttal, pages 27-29.) In discovery responses in Oregon, the Company clearly stated that “the 25% and 75% exceedence levels may not represent the 25% and 75% for total system hydro…” (OPUC Docket No. UE 191, ICNU/13.34, available via agreement by the Company in the response to CCS 2.39). In another data response the Company indicated it was uncertain whether it should continue to use the 25% and 75% scenarios instead of the simple median (50% case). (OPUC Docket No. UE 191, ICNU/13.33, again via the response to CCS 2.39). While I additionally recommend use of the proper hydro weights in this case, use of the median scenario only is a solution the Company has supported in past cases.

Q. ARE THERE ANY OTHER HYDRO MODELING ISSUES?

A. Yes. The Company uses an arbitrary, non-physical input in GRID called the “Hydro Reserve Input Parameter.” This represents the fraction of the difference between the hydro weekly energy and the project maximum capacity that is held for reserves.[44] As this input is increased, more hydro capacity is assigned to carrying reserves. This parameter is not a measurable input, such as the capacity or ramp rate of the unit. Nor is it a factor actually used in the real time operations.

[44] GRID V6.2 Algorithm Guide, Page 15.

Rather, it is a judgmentally determined input, without any supporting documentation provided by the Company.

The Company assumes that this parameter should equal .85 most hours of the day, but for the period 7 am to 10 am, it is set equal to one. This has the impact of increasing the amount of hydro generation allocated to reserves, thereby increasing NVPC. Because these three hours already have reserve allocations to hydro that exceed the hourly requirements (without the increase in the Reserve Input Parameter), there is no apparent justification to further increase the reserve allocation. This simply reduces the value of hydro generation to the Company.

Q. WHAT IS YOUR RECOMMENDATION?

A. Discovery regarding this issue produced limited information as of the time this testimony was prepared. The Company may be able justify these inputs. For that reason, I have not included this adjustment in my recommended NVPC results. Absent a meaningful explanation from the Company, I recommend the Commission reverse this input in GRID. This results in the adjustment shown on Table 1.

VI. THERMAL DERATION FACTORS

Q. EXPLAIN THE USE OF THERMAL DERATION FACTORS IN GRID.[45]

A. In GRID, thermal deration factors (also called unplanned outage rates) control the amount of generation available from thermal units. The more energy available, the lower net variable power costs. If a generator has an average unplanned outage rate of 5%, GRID assumes a thermal deration factor of 95%. This means that only 95% of the unit's capacity is available to produce energy. The remaining capacity is assumed to be permanently unavailable.

Q. ARE THERMAL DERATION OR UNPLANNED OUTAGE FACTORS AN IMPORTANT DRIVER IN OVERALL NET POWER COSTS?

A. Yes. PacifiCorp's thermal unplanned outage rates have increased substantially in the past decade. Exhibit CCS 4.12 shows that PacifiCorp's four-year rolling average unplanned outage rates have increased by more than 40% compared to comparable figures for 1999. Also troubling is the fact that 81% of PacifiCorp's generating units have seen their unplanned outage rates increase over the past eight years.

Q. WHY DID YOU COMPARE CURRENT FIGURES TO THE 1999 UNPLANNED OUTAGE RATES?

A. I have been analyzing PacifiCorp's unplanned outage rates in rate cases dating back to 1998 and there has been a continued upward trend to the present time. The 1999 figures were worse than the 1997 four-year average, for example. Both the 1999 and 2006 four year averages exclude the major Hunter outage that occurred in November 2000 providing a fair comparison of outage trends.

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45 Hereafter in this testimony, unplanned outages and outage rates will be discussed, as distinguished from the planned outages discussed above. Even if the text doesn't specify it, I will be discussing unplanned outages.

Q. IS THIS TREND A RESULT OF PLANT AGING?

A. No. Review of NERC figures shows that, while the national fleet of coal plants has aged substantially in recent years, outage rates have decreased, not increased.[46]

Q. HAS THE INCREASE IN UNPLANNED OUTAGE RATES INCREASED POWER COSTS?

A. Yes. To estimate this cost I used GRID to compute the change in net variable power costs resulting from a 10 MW change in coal capacity. I then applied this result to develop an annual average cost of the increased amount of outage capacity. As shown in Exhibit CCS 4.12, the result is more than $55 million per year on a total Company basis. This increase in outages results in an increase in cost to Utah customers of more than $23 million per year. An additional problem is that the increase in outage rates has also led to the need for additional thermal capacity, further increasing system costs. To put this into perspective, the increase in outage capacity (189 MW) is nearly equivalent to the total capacity of the West Valley plant.

Q. WHICH OF PACIFICORP'S COAL UNITS HAVE THE HIGHEST UNPLANNED OUTAGE RATE?

A. The four Bridger units have the highest outage rates among all the coal plants owned by the Company.

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[46] See exhibit CCS 4.13.

Q. COMPARISON OF HISTORICAL AVERAGE FIGURES DOES NOT DIRECTLY ADDRESS WHY UNPLANNED OUTAGE RATES HAVE INCREASED. IS THERE EVIDENCE THAT THE INCREASE IN OUTAGE RATES IS DUE TO POOR OPERATION AND MANAGEMENT PRACTICES?

A. Yes. To investigate the causes of these outages, I examined numerous "Root Cause Analysis" ("RCA") reports for outages that occurred at PacifiCorp's coal-fired generators during the 48-month period ending June 30, 2007. I analyzed these RCA reports and determined whether the cause of the outages was due to poor management, personnel or maintenance errors, or other avoidable causes. It is important to point out that in the vast majority of RCA reports I reviewed, PacifiCorp did not report the outages to NERC as being due to personnel or maintenance errors[47] but instead, were reported as having other causes. Despite this, I found many instances where the RCA reports indicated personnel or maintenance errors. PacifiCorp should be held responsible for the costs of these outages because they appear to be contributing to the Company's increasing outage costs. It is significant that nearly all of these events occurred at a single plant – Jim Bridger, the plant that has the highest outage rates on the PacifiCorp system.

Q. CAN YOU PROVIDE SOME EXAMPLES?

A. Yes. Confidential Exhibit CCS 4.14 presents excerpts from RCA reports that show a substantial number of outages were caused by Company errors, mismanagement or other avoidable causes. In total, I identified thirteen such events, eleven of which occurred at Jim Bridger.

47/ PacifiCorp coded a very substantial number of outages due to such causes, but these tended to be small events, generally lasting only a few hours. The number of such events has also been increasing substantially over the years.

Q. THE EVENTS DISCUSSED IN EXHIBIT CCS 4.14 WERE REPORTED TO NERC AS BEING DUE TO CAUSES OTHER THAN EMPLOYEE OR CONTRACTOR ERRORS. DID THE COMPANY ALSO REPORT ANY OUTAGES AS BEING DUE TO SUCH ERRORS?

A. Yes. For example, during the period ending June 30, 2007, the Company identified 170 events at coal plants due to causes that it did report to NERC as being due to operator, maintenance or contractor errors. Review of this data showed that more than half of these events occurred at the Bridger plant.

Q. WHAT HAS BEEN THE TREND IN REPORTED ERROR OUTAGES FOR PACIFICORP?

A. The Company has seen a substantial increase in the number of outages due to errors since the Utah Power and Light - Pacific Power and Light merger took place. The chart below shows the number of outages due to errors for the period 1990 to 2006 for PacifiCorp coal plants. These include outages reported to NERC as due to employee or contractor errors. The NERC average for the most recent four-year period available is also shown. As the chart shows, the Company has experienced a tripling of outages due to errors and now has three times the national average number of errors.[48] However, over recent years, a growing proportion of such events have occurred at the Bridger plant. If Bridger were removed, the remaining plants are closer to (but still somewhat above) the NERC averages. While the NERC average for error outages at a four-unit plant is two events per year, the Bridger plant experienced more than 90 events in the four-year period.

[48] Based on NERC data a fleet of 26 coal units would experience approximately 14 events per year, or .55 per unit/year.

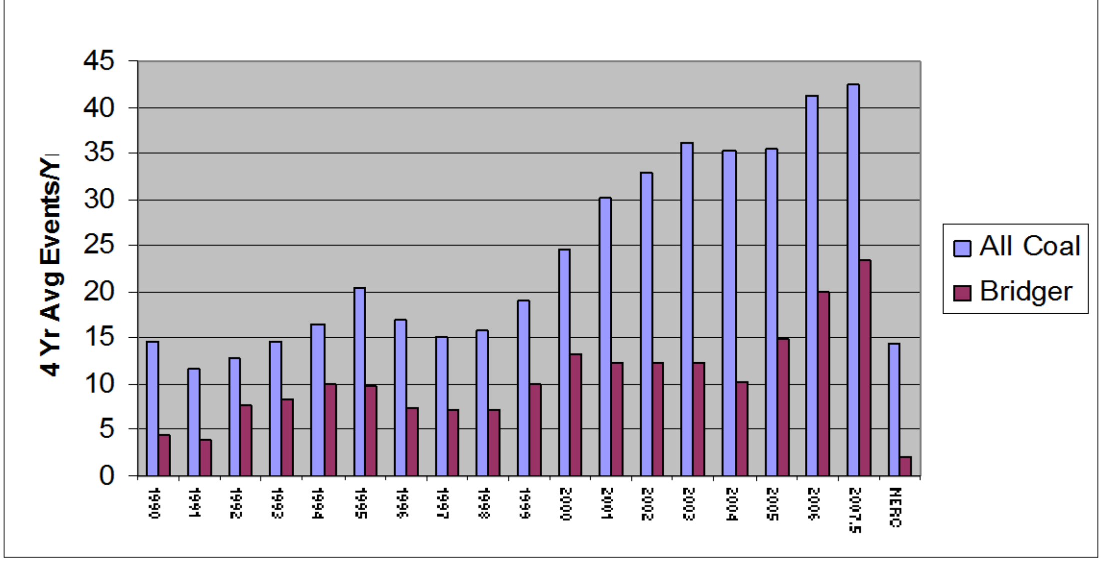

Figure 4: PacifiCorp Trend in Error Outages: 1990-Mid 2007

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission make an adjustment to reduce the amount of energy lost due to both the reported and unreported employee, maintenance and contractor errors at Bridger to the NERC average. This would reduce outage-related energy in the test year by more than 75,000 MWh, and is equivalent to reducing the Bridger outage rates by .75%. The impact of this adjustment is shown on Table 1.

Q. IS IT REASONABLE TO MAKE AN ADJUSTMENT INVOLVING ONLY THE BRIDGER PLANT AND IGNORE THE COMPANY'S OTHER PLANTS?

A. The performance of the Company's remaining plants is comparable to (neither well above, or far below) the NERC averages. The Bridger plant is a poor performer relative to not only the NERC averages, but also as compared to the Company's other coal-fired power plants. Owing to the overall declining trend in plant availabilities and poor performance of the Bridger plant relative to its peer group, a disallowance is clearly warranted.

Monthly Outage Rates

Q. HOW DOES THE COMPANY MODEL UNPLANNED OUTAGE RATES IN GRID?

A. The Company differentiates unplanned outage rate on a monthly basis using the average monthly outage rate computed from the four-year period. This procedure marks a significant departure from the modeling methods used by the Company in Docket No. 01-035-01. In the past, the Company assumed that unplanned outages would occur with the same probability every month of the year. In this case, the Company now assumes outage rates will vary by month. As with the hydro modeling issue, this is development that has been the subject of debate in the previously settled cases in Utah. Only the Washington Commission has ruled on this issue, deciding against this new procedure in the most recent case in that state.[49]

Q. IS THIS AN INDUSTRY STANDARD PRACTICE?

A. Most definitely not. PacifiCorp's approach is quite unusual and certainly not industry standard. While I am aware that a few utilities have briefly experimented with modeling seasonal outage rates, the vast majority of utilities assume a constant outage rate throughout the year. The primary reason for this is that there are few physical factors affecting thermal power plant operation that would result in outage rates varying significantly on a monthly or seasonal basis. There is

[49] Washington Utilities and Transportation Commission, Docket No. UE-061546, Final Order Paragraphs 136 – 137. I do acknowledge the WUTC order is rather unclear on this issue, however, in its most recent filing in Washington (Docket No. UE-080220), the Company excluded both its ramping and monthly outage rate adjustments based on that order.

really no engineering or statistical basis to assume a generating unit would be significantly more reliable in January than July, for example. In its response to CCS 21.11, the Company could not identify any factors that would result in monthly variation in unplanned outage rates.[50]

Further, unplanned outages are quite random by nature, and use of monthly statistics can produce very misleading results. Just one "bad month" can skew an average computed from only four data points. For example, for Gadsby Unit 2, the monthly outage rate methodology produces rather absurd results. Based on Company analysis, Gadsby Unit 2 will be on forced outage 96% of the weekdays in December, but will be available 100% of the time on weekdays in January. It makes no sense to assume that on a normalized basis the unit will almost never be available on weekdays in December, but will always be available in January. Normalization is supposed to "smooth out" variations for a single month or year to produce results that are more realistic overall. The Company's approach does just the opposite. It "de-normalizes" the outage rate data.

Q. ARE THESE MONTHLY OUTAGE RATES STABLE OVER TIME?

A, No. In the recent Wyoming case the Company used the 48 months ended December 31, 2006 to compute outage rates. In this case, the Company used the 48 months ended June 30, 2007, a change of only six months. However, in Wyoming, the Company's method showed a June weekday outage rate for Gadsby Unit 1 of 99% (without ramping), now the Company computes an outage rate of only 1% if ramping is excluded.[51]

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[50] Mr. Hayet also comments on PacifiCorp's approach in his testimony.

[51] The reasons ramping should be excluded will be discussed later in this testimony.

Q. CAN YOU PROVIDE A SIMPLE ANALOGY THAT EXPLAINS THE FALLACY OF THE COMPANY'S APPROACH?

A. Yes. The Company's approach is similar to assuming that because a random event occurred in a particular month in the past, it would likely occur at the same time in the future. If my car broke down in February 2007, does that mean it will break down again in February 2008? I don't think so, but that's the logic the Company is using.

Q. DOES THE COMPANY'S PROPOSED MONTHLY OUTAGE RATE MODELING INCREASE OR DECREASE NVPC?

A. In this case, it produces a small decrease in NVPC. However, given the lack of a sound engineering basis, statistical data or common sense argument supporting it, I believe the Company's approach should be rejected. Accordingly, I recommend that the Commission reject the monthly modeling of outage rates and increase net power costs by the amount shown on Table 1.

Thermal Ramping

Q. EXPLAIN THE THERMAL RAMPING ADJUSTMENT TO GRID OUTAGE RATES.

A. Ramping represents the energy lost after outages due to the time required to ramp up a unit to its desired generation level. GRID does not account for this energy because it uses a constant deration method rather than a simulation of full outages. The Company proposes to adjust outage rates to reflect the lost energy it assumes results from ramping.

Q. DO YOU RECOMMEND THE COMMISSION ACCEPT THIS PROPOSED "CORRECTION"?

A. No. This adjustment was ostensibly proposed by the Company to better represent the operation of thermal units. PacifiCorp used this technique in recent cases in some states, motivated by a specious assumption that GRID was producing an excess of coal-fired generation.[52] To address the ramping issue, PacifiCorp creates "phantom outages," inflating its outage rates.

I believe it is important to note that many of the Company's recent cases in Oregon, Utah, Washington and Wyoming have been settled (at least regarding this issue) or dismissed, and only the Washington Commission has ruled on this issue.[53] In Docket No. UE-061546, the Washington Commission rejected the ramping adjustment proposed by the Company. The Company did not include this adjustment in its most recent Wyoming and Oregon cases, but has stated that the ramping adjustment was left out by mistake. Along with the hydro modeling

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52/ Re PacifiCorp, OPUC Docket No. UE 170, Exhibit PPL/604, page 2 (Supp. Direct Testimony of Mark Widmer).

53 Washington Utilities and Transportation Commission, Docket No. UE-061546, Final Order Paragraphs 136 – 137.

and monthly outage rate issues, the thermal ramping issue has never been presented to the Utah Commission.

Q. IS MODELING OF THERMAL RAMPING IN THE MANNER USED BY THE COMPANY STANDARD INDUSTRY PRACTICE?

A. No. Based on my nearly thirty years of experience working with various power cost models, this approach is extremely unusual and contrary to standard industry practice. The North American Energy Reliability Council ("NERC") publishes a standard formula for computation of forced outage rates, and the approach proposed by the Company does not use the NERC formula.

Q. CAN YOU ILLUSTRATE SOME OF THE PROBLEMS WITH THE COMPANY'S RAMPING ADJUSTMENT?

A. Yes. Exhibit CCS 4.15 provides a copy of the response to CCS 6.11 and compares that data to data obtained in the response to CCS 2.8. The response to CCS 6.11 shows the Company's calculation of the ramping adjustment for Gadsby Unit 3 for the month of March, 2007. The worksheet shows how the ramping calculation is performed each hour. The Company's methodology assumes that <u>any</u> difference between the actual loading of a unit after it has been started up and 90% of its available capacity is due to ramping. This is a very significant adjustment for Gadsby Unit 3 in the calculation of March outage rates because this is the only March during the four-year period ending June 30, 2007 when Gadsby Unit 3 was actually called upon to run. In total, the unit generated 916 MWh during that month, *but lost 994 MWh due to ramping*.

Q. PLEASE MORE FULLY DESCRIBE THE PROBLEMS WITH THE COMPANY ANALYSIS.

A. The first problem is that the Company assumes that unless a unit is running at 90% of its full loading, it must be losing generation due to ramping, no matter how long it has been running. In the Gadsby Unit 3 example, on March 28, 2007, the Company assumes that even after the unit ran for eleven hours (when the unit is cycling down to a reserve shutdown) it was still losing energy due to ramping. In the last hour of operation on that day, the unit produced only 5 MW (as compared to available capacity of 100 MW). The Company assumes this resulted in 95 MW lost due to ramping, even though it acknowledged in response to CCS 6.11 that the unit was only on line part of the hour and heading into reserve shutdown status.

This is a very flawed approach, however, because there is no basis for the assumption that the unit would otherwise be dispatched to at least 90% of its full loading if not for ramping. The real time dispatch may determine, for example, that the most economic dispatch is something less than full (or even 90% of full) loading for a unit.

Alternatively, the unit may be assigned to carry reserves. Exhibit CCS 4.15 also shows the hourly allocation of reserves to Gadsby Unit 3 during March 2007 based on the data provided in CCS 2.8. It shows that the unit was assigned to carry reserves every single hour when the Company assumed it would otherwise be losing generation to ramping. In this example, 487 MWh which the Company assumed to be lost due to ramping was actually assigned to reserves. This amounts to almost half of the ramping adjustment for the month. The fact that the unit had so much capacity allocated to spinning reserves clearly indicates that it was never intended to run at full loading. Instead it was started to provide reserves and therefore operated at much less than full load. Under the Company's analysis of ramping, all of this was ignored. Were these facts considered, virtually none of the lost ramping energy should be counted.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE THERMAL RAMPING ISSUE?

A. The Commission should reject the ramping adjustment. It is demonstrably overstated, it was recently rejected by the Washington Commission and the Company has not even proposed the adjustment in its two most recently filed cases. Reversing the Company's proposed ramping adjustment is included in my Table 1.

VII. CURRANT CREEK AND LAKE SIDE MODELING

Q. ARE THERE ANY OTHER PROBLEMS WITH THE MODELING OF COMBINED CYCLE UNITS IN GRID?

A. Yes. In GRID the Company models the duct firing capabilities of Currant Creek and Lake Side as generation resources that are independent of the underlying combined cycle plant. This has created problems where the duct firing capacity runs at times when the combustion turbines and steam generator are not running.[54]

A more serious problem is that GRID frequently shows duct firing operation of Currant Creek when the combustion turbines and steam generator of Currant Creek are operating at their minimum loading. This is neither an economical nor realistic mode of operation, as duct firing capability has a higher heat rate than the combined operation of the combustion turbines and steam

[54] See the response to CCS 6.41

generator. During the on-site interviews conducted on February 15, 2008, the real time operational staff members indicated this was not the normal mode of operation. Yet GRID shows this unrealistic operation more than 2300 hours per year, or 50% of the time that duct firing is in operation.

A further problem is that in GRID, the Company does not allow the duct firing capacity of Currant Creek and Lake Side to carry spinning reserves, though they are allowed to carry ready (quick start) reserves. This is again, unrealistic. When Current Creek is not running, it is impossible for the duct firing to start in ten minutes, while it can do so if the plant is already running.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING DUCT FIRING?

A. The Company needs to develop a modeling enhancement for GRID that allows proper modeling of all modes of operation for combined cycle generators. I recommend the Commission require this be done before the next general rate case is filed.

As an interim solution for the Commission's consideration in this case, I have combined these resources into a single unit in GRID. Because I would like to evaluate the Company's response to this proposal from a modeling perspective, I have not reflected this adjustment in the totals shown on Table 1. However, absent the Company providing a sound reason not to proceed with the adjustment, I recommend the Commission adopt it. This produces a reduction to NVPC in the amount shown on Table 1.

Q. PLEASE EXPLAIN YOUR PROPOSED INTERIM SOLUTION IN MORE DETAIL.

A. In reviewing the hourly loadings of the combined Currant Creek resource, I was able to develop a much more realistic dispatch than the Company's modeling approach. This approach eliminates the unrealistic operation of the resource and also reflects the reserve carrying capability when duct firing is in operation.

The Company has already estimated the heat rate curves for combustion turbines and steam generator combining normal and duct firing modes of operation. Thus, the input heat rate curve used in GRID reflects operation from minimum loading to full duct firing operation. Because duct firing is less efficient, this may overstate the heat rate for conventional operation of the plant, providing yet one more reason to combine the resources into a single resource in GRID.

Q. HAVE YOU EXAMINED ANY ALTERNATIVE APPROACHES?

A. Yes. Another approach would be to simply allow the Currant Creek duct firing capability to carry spinning reserves. I've examined the hourly results under this approach extensively, and believe it provides a more realistic operation than the Company's modeling as well. While this technique accounts for the reserve carrying capability of duct firing, it does not eliminate the problem related to operating duct firing before the steam generator is fully loaded. This adjustment produces a NVPC reduction of approximately $2 million.

Q. HAS THE COMPANY CORRECTLY COMPUTED THE OUTAGE RATE FOR CURRANT CREEK IN GRID?

A. No. The Company used an unsupported and incorrect formula to compute the Currant Creek outage rate in GRID. Further, even accepting the formula used by the Company, it had incorrect inputs for the combustion turbine capacities, using

180 MW rather than 140 MW. The Company calculated an annual average outage rate of 4.81% compared to my corrected outage rate of 4.75%. Had I simply corrected the capacities used in the Company's formula, the outage rate would have been 4.10%. Also, the Company overstated the number of days of required maintenance for Current Creek because it considered a planned outage of one CT as resulting in an outage of the entire plant. In reality, when one CT is down, the plant can still run at half of its capacity. I have corrected the calculation of Currant Creek's planned and unplanned outage rate in GRID, resulting in the adjustment shown on Table 1.

VII. GENERATING UNIT REPRESENTATION IN GRID

Q. EXPLAIN HOW GENERATOR OUTAGES ARE REPRESENTED IN GRID.

A. As discussed earlier, GRID uses what is known as the deration method to model outages. Outage rates are assumed to reduce the available capacity. This means that if a unit has 100 MW of capacity, and a 5% outage rate, the unit is represented in GRID as a 95 MW unit that is available 100% of the time. This is an industry standard technique. Though dated, this approach has been used in various models for many years. In effect, GRID replaces the capacity of each unit with its "expected value." The expected value, MW_e, for a unit is computed as shown below:

MW_e = MW x (1-EFOR), where EFOR = the outage rate of the unit, and MW is the maximum capacity of the unit.

The above formula is appropriate because it represents a situation where the unit is fully available (i.e. to MW, the maximum capacity) (1-EFOR)[55] percent of the time, and available at zero MW (because it is on an outage) EFOR[56] percent of the time.

I have no objection to this representation in GRID, even though there are other, more sophisticated, methods such as Monte Carlo modeling that may provide more realistic simulations. While it is not immediately obvious, proper use of the deration method also requires other adjustments to unit characteristics be made as well. First of all, the unit *minimum capacity*, MW(min), should also be derated by the same amount as the *maximum capacity*. The expected value of the minimum capacity, $MW(min)_e$ is given by the formula below:

$$\mathbf{MW(min)_e = MW(min) \times (1\text{-}EFOR).}$$

The simple, and intuitive, explanation is that unless this adjustment is made, the unit's *minimum* capacity could exceed its *maximum* capacity. While this may seem far fetched, it actually did happen in some situations in the GRID simulations for the test year. For example, in May 2008, Currant Creek was assumed to have a rather large outage rate. As a result, the derated maximum capacity (338.5 MW) was less than the assumed minimum capacity (340 MW) for Currant Creek. Thus, use of the deration method as applied by the Company

[55] 95% in the example above.
[56] 5% in the example above.

results in the model violating minimum loading constraints, albeit by a small amount.[57]

A more detailed and mathematical explanation is that when simulating operation at minimum loadings, it is also necessary to compute the expected value of the loading. If the unit is expected to be operating at minimum loading during a given hour, the expected value of its generation is MW(min) 1-EFOR percent of the time, and zero EFOR % of the time. This is no different than the case discussed above involving maximum capacities. While the Company derates the maximum capacity for outages in GRID, it does not do so for the minimum capacity. Given the substantial number of resources now operating at minimum loading, this has become a very serious oversight.

Q. ARE THESE THE ONLY ADJUSTMENTS REQUIRED?

A. No. There must also be a corresponding adjustment to the heat rates, which is not being done in GRID either. Generating units are represented in GRID using a polynomial heat rate equation:

$$\textbf{Heat input (hour h)} = A+B \times mW_h + C \times mW_h^2$$

Here mW_h is the loading of the unit in hour h.

If, for example, the unit is expected to be running at its maximum capacity, GRID will treat it as a smaller unit running at less than full load. Returning to the original example of a 100 MW unit, GRID sees it as a 100 MW unit that is only running at 95 MW. In this case, the actual heat input of the unit

[57] While minor in this case, in the Wyoming case, the discrepancy was much larger, as GRID showed Currant Creek running as low as 288 MW, more than 50 MW below its stated minimum.

will be overstated, because units are generally most efficient at their full loading point. The heat rate curve used in GRID will therefore overstate fuel costs.

This is again related to the concept of expected value. The expected value of the heat input for the 100 MW unit is as follows:

Heat input = (A+B x 100 + C x 100^2) times 95% + 0 times 5%.

In effect, the above equation shows that the expected value of the heat input should be computed as (1-EFOR) times the heat input at full loading. GRID, however, would compute the heat input as shown below:

Heat Input (GRID) = A+B x 95 + C x 95^2

While it appears to be a rather minor adjustment in the case where a unit is fully loaded, it can be very important in some cases. Further, because unit efficiencies typically decline as unit loadings decrease (moving down the heat rate curve), ignoring this adjustment will increase NVPC. Even worse, not making this type of adjustment could produce absurd results in some cases. As discussed earlier, it is assumed in GRID that one of the Gadsby units would have an outage rate approaching 100% in December 2008. It is possible in such cases that using a very large outage rate would result in a dispatch of the unit at a mere fraction of its actual capacity, even if it was intended to run at maximum loading. Absent any kind of adjustment to the heat rates, this would result in an absurdly high operating cost for the resource. While seemingly unlikely, this scenario did occur in the recent Wyoming case.

Q. WHAT FURTHER ADJUSTMENT IS NEEDED?

A. In this case, it is necessary to adjust the heat rate curve so that it produces the same heat input at the derated maximum and minimum capacities, as the unit would actually experience in normal operation. The proper adjustment to the heat rate curve is as shown below:

$$\textbf{Heat Rate Curve Adjusted} = \mathbf{A \times (1\text{-}EFOR) + B \times mW_h + C/(1\text{-}EFOR) \times mW_h^2}$$

Q. HAVE YOU PREPARED AN EXHIBIT THAT PROVIDES A MORE DETAILED ANALYSIS JUSTIFYING THESE INPUT CHANGES TO GRID?

A. Yes, Exhibit CCS 4.16 presents an example that further demonstrates why these adjustments are necessary. It shows that unless these adjustments are made to GRID it will overstate NVPC using a series of outage scenarios. The values for these adjustments are shown on Table 1.

Station Service Modeling

Q. EXPLAIN STATION SERVICE MODELING IN GRID.

A. The Company proposes to include a zero revenue sales transaction in GRID to reflect station service requirements during plant outages, increasing NVPC.

Q. IS THE PACIFICORP METHOD STANDARD INDUSTRY PRACTICE?

A. No. Based on my experience in working with production cost models, this approach is quite novel and contrary to standard industry practice.

Q. DOES THE COMPANY TREAT ALL STATION SERVICE REQUIREMENTS IN THIS MANNER?

A. No. More than 99% of station service requirements are reflected in unit heat rates in GRID. Less than 1% of station service requirements are modeled via this zero revenue sales transaction. This is a negligible amount of station service and hardly worthy of a special adjustment. The vast majority of station service requirements occur when the plant is running, and there is no justification for treating a tiny fraction of station service requirements differently from the rest. It is the standard industry practice to reflect all station service requirements in heat rates because it really amounts to a reduction to the efficiency of generating plants.

Q. HOW DO YOU PROPOSE TO TREAT STATION SERVICE REQUIREMENTS IN GRID?

A. I recommend reflecting all station service requirements in the calculation of unit heat rates. This is a balanced approach because it does recognize the efficiency degradation associated with the additional energy requirements during outages. At the same time, it reflects the efficiency gains when units perform above their normal ratings. This adjustment is shown on Table 1.

IX. OTHER ISSUES

Wind Integration Expense

Q. HAS THE COMPANY MODELED WIND INTEGRATION COSTS IN GRID?

A. Yes. The Company includes reserve requirements equal to 5% of on-line wind capacity for contingency (spinning) reserves. It has also modeled an additional cost of approximately $1.1/MWh, based on an analysis contained on page 193 of Appendix J of the PacifiCorp 2007 IRP. This issue was discussed during the on-site interviews on February 14, 2008. We inquired as to why the Company modeled wind integration costs in two parts. It was explained that the GRID model computed the inter-hour reserve requirement, while the $1.1/MWh charge was for intra-hour reserve requirements. Based on the analysis contained in the IRP, the intra-hour wind integration costs are equal to the additional cost.

Q. DO YOU AGREE WITH THIS APPROACH?

A. I do not question the IRP analysis at this time. However, the Company did not correctly apply the IRP findings to GRID. Page 192 of Appendix J to the IRP shows that the additional reserve requirements for the Company's planned 2000 mW wind portfolio is equivalent to an increase in reserve requirements of 43 MW (or about 2% of installed wind capacity.) However, during the test year the Company will have far less than 1000 MW of wind capacity installed. The figure on page 192 of the Appendix J shows that for less than 1000 MW of wind capacity installed, the incremental reserve requirement is less than 1% of total capacity. The formula shown on Page 192 shows that if the lower reserve requirement is inserted into the equation, much lower wind integration costs result.

Q. IS THIS HOW YOU MODELED THESE ADDITIONAL WIND INTEGRATION COSTS?

A. No. A much simpler approach is to increase the wind resource reserve requirement from 5% to 6%. So long as installed wind capacity is less than 1000 MW there is less than a 1% change in overall reserve requirements due to intra hour effects. This correction results in the reduction to NVPC shown on Table 1.

Reserve Requirements for Non-Own Generators

Q. PLEASE EXPLAIN THIS ISSUE.

A. There are many independent generators inside PacifiCorp's control area and the Company is required to provide reserves for some of these generators. In some cases, the generators do not pay the Company for such reserves because they were reflected in the contract prices for generation provided, such as in the case of QFs. An issue arises because the Company has included the requirements for certain generators that self supply reserves, and/or who do not pay the Company for any reserves where the above stated exceptions don't apply. (See the response to CCS 7.11). In these cases, the associated requirements should be removed from GRID because the generator doesn't require reserves from the Company and/or are not compensating the Company for the service. Table 1 shows the impact of correcting these inputs to GRID.

Transmission Wheeling Expense

Q. PLEASE EXPLAIN YOUR TRANSMISSION WHEELING EXPENSE ADJUSTMENTS.

A. These adjustments (shown on Table 1) correct four problems in the transmission costs inputs. <u>First</u>, the Company includes a pro-forma adjustment for the Goodnoe wind facility for the entire test year. However, Goodnoe has been delayed and is not now expected to come online until June 2008. As a result, I removed that pro-forma until June 2008. The Company agreed that the Goodnoe pro-forma adjustment was incorrect in its response to CCS 21.1

<u>Second</u>, the Company included escalations for several transmission contracts in the Test Year. Many of these reflect a BPA rate increase that took

place in October 2007. However, the Company developed these escalations from a rather crude comparison of changes in individual rate components rather than billing out the actual charges as applied to its requirements.[58] Based on analysis of October and November 2007 actual data these escalations were overstated.

Third, the Company acknowledged that it could not support the wheeling rate assumed in the Borah Brady transmission cost pro-forma adjustment.[59] I recomputed this charge based on a rate schedule obtained from the Idaho Power OASIS.

Finally, I have included the benefit of transmission imbalance charges the Company collects from third party customers. Under the Company Open Access Transmission Tariff, the Company charges third party customers when their load exceeds resources or their load is less than resources. The imbalance charges are discounted below or marked up above the market price depending on whether the imbalance results in a purchase or sale. In the end, this amounts to a low cost source of energy for the Company, which it has not reflected in GRID. Exhibit CCS 4.17 is a copy of a data request WIEC 5.3 from the current Wyoming PCAM docket explaining this issue in more detail. I quantified this adjustment based on data for the 12 months ended December 31, 2007, but would agree to use a four-year average if the data becomes available.

Q. WERE THERE ANY OUTSTANDING DISCOVERY REQUESTS AT THE TIME YOUR TESTMONY WAS PREPARED?

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58 Telephone conference on March 26, 2008 with Dave Taylor and Hui Shu of the Company.

59 Id. The Company provided the Idaho Power OATT in support of the pro-forma in CCS 21.2-2. However, this document contains no actual tariff charges. The Company indicated that the charges used were taken from the Idaho Power OASIS, but the current figures differed from those used by the Company.

A. Yes. The Company's response to CCS 21.5 is late and not available when this testimony was prepared. CCS 21.5 dealt with modeling of transmission capabilities in GRID. Further, as a result of discovery posed in another state (Washington) it seems that the answer to another CCS request in this case was incomplete. CCS 2.11 requested the Company provide data on non-firm transmission flows. Based on the answers provided to CCS 2.10 and 2.11 it appeared that the Company did not have any such analysis and none was provided. However, we recently obtained a data response in the current Washington case, which did provide data concerning non-firm transmission flows. As a result, the Committee reserves the right to supplement my testimony should further inquiry into these transmission matters identify any significant issues.

X. CONCLUSION

Q. PLEASE SUMMARIZE THE CONCLUSIONS OF YOUR TESTIMONY.

A. I have presented a number of detailed adjustments to the GRID model study, and recommend the Commission adopt them to properly normalize net power costs. To provide some perspective, I would point out that while I have identified a number of adjustments my overall recommended reduction to NVPC is only about 5.7% of the Company's total request. Further, a significant number of my recommended adjustments relate to data input assumptions or normalization procedures rather than problems in the model logic itself. The table below summarizes the adjustments I recommend and categorizes them to model logic

250
260 w
434 s

corrections, data corrections or other issues. Model adjustments are those related to correcting deficiencies in the model logic, such as those related to uneconomic generation. Data corrections are items that concern input assumptions. Other issues include disallowances of specific outages and the pricing of the SMUD contract.

Table 4

Summary of Adjustments

Basis	Total Co. $	% of Request	% of Adj.
Model	**(19,934,672)**	**-1.9%**	**33.5%**
Data	**(30,719,076)**	**-2.9%**	**51.7%**
Other	**(8,796,891)**	**-0.8%**	**14.8%**
Total	**(59,450,639)**	**-5.7%**	**100.0%**

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A**.** Yes.