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	))))))))	**Docket No. 08-035-38** **Direct Testimony of Randall J. Falkenberg On Behalf of the Utah Committee of Consumer Services**

Redacted –
Grey Highlights indicate redacted confidential Material

February 12, 2009

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 Committee of Consumer Services ("the 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's 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 ("NPC") for the projected test period ending December 31, 2009. I also address issues related to the rate treatment of new wind energy resources.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I have identified and quantified 32 adjustments to the Company's GRID study and new wind resources. These adjustments are summarized in more detail below and on Table 1 shown and addressed in more detail later in this testimony.

<u>PART 1: Net Variable Power Costs (GRID)</u>

1. **The Company has made a number of adjustments and improvements to its GRID modeling and input assumptions since the last case which I address in my testimony. While PacifiCorp's requested NPC in this case is more reasonable than in the prior case, the overall request for $1,053.3 million (total Company) in NPC is overstated by $32.5 million. I recommend NPC of $1,020.7 million, resulting in a reduction to Utah allocated NPC of $13.1 million.**

<u>Uneconomic Generation Adjustments</u>

2. **In Docket No. 07-035-93 the Commission determined (and the Company acknowledged) a commitment logic error existed in GRID. In its December, 2008 filing the Company used a more rigorous "screening" method than in the past to address this issue. While an improvement, the Company's method does not consider whether units should be committed on specific days, nor does it consider start up costs in its analysis. Further, the Company limited application of this approach to combined cycle units, rather than all of its cycling units. I present a more rigorous solution to the problem and apply it to all gas units. Table 1, items 1-6, present the results of these adjustments.**

3. **While I agree with the Company's inclusion of start up costs in GRID, the figures used in the test year are overstated. The Company ignores the value of energy produced during the start up process. Correcting this oversight produces the adjustment shown as item 7 of Table 1.**

4. **The Company has not applied the daily screening methodology adopted by the Commission in Docket No. 07-035-93 to call options. Instead, it applied a monthly screening method rejected by the Commission. Correcting this oversight results in the adjustment shown on Table 1 as item 8.**

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

5. The Committee proposes indexing the imputed price of the SMUD contract to the actual contract price so that the $94 million "up front payment" is returned to ratepayers over the life of the contract. This adjustment is shown as item 15 on Table 1. This adjustment addresses concerns the Commission stated in its Order on Reconsideration in Docket 07-035-93.

6. The Company incorrectly models the Black Hills Power, UMPA II, Sierra Pacific and Public Service Colorado contracts. The Company assumes these contracts will take power primarily in high load hours and use very little power during low load hours. Review of the actual contract delivery patterns shows these contracts should be modeled with a flatter profile. The value of these adjustments is shown as items 9-12 on Table 1.

7. In each of the past four years the Company has agreed to a non-generation agreement with the Biomass project. The Committee recommends a comparable non-generation agreement be assumed for this case. I include this adjustment on Table 1 as item 16.

8. The Company has errors in its modeling of several QF contracts (Douglas Forrest Products, Kennecott and certain Oregon wind farms) and uses an incorrect forward price curve in its modeling of the Grant Reasonable contract. These errors are corrected on Table 1 as items 13-14.

Planned Outage Schedule

9. While the Company presents a somewhat more realistic planned outage schedule than in Docket 07-035-93, it still uses the same opaque and highly subjective methodology. As a result, outages are scheduled in earlier, higher cost, periods in GRID than would occur in actual practice.

10. The Commission should adopt an objective and transparent method for modeling planned outage schedules. I propose to use the composite result from the four actual planned outage schedules for the 48 months period ending June 30, 2008 in GRID. Use of the actual planned outage schedules reduces NPC by the amount shown as item 17 on Table 1. This method is quite comparable to the proposal adopted by the Commission in Docket 07-035-93.

Hydro Modeling

11. In its December filing the Company has departed from its recent practice of modeling three hydro scenarios (Wet, Median and Dry) in

favor of use of the Median scenario only. I endorse this approach as an acceptable solution to this longstanding dispute. This adjustment is already factored into the Company's December baseline.

<u>Forced Outage Rate Modeling</u>

12. The Company has already eliminated the impact of two outages that were found to be imprudent and disallowed by regulators in Oregon. I agree with this adjustment. I also recommend disallowances related to five other imprudent outages. I present root cause analysis reports that demonstrate the Company was at fault for these outages.

13. Nearly half of the lost energy factored into the Currant Creek outage rate was the result of a single outage in May, 2006. The Company has overstated the lost energy from this outage because it assumes the plant would have run around the clock, rather than cycling during that period. It also appears the Company has overstated lost energy in its calculation of the Currant Creek outage rate. All outage adjustments are included in item 18 on Table 1.

<u>GRID Modeling Issues Deferred from Docket 07-035-93</u>

14. GRID derates maximum generator capacities to reflect unplanned outages. While this is an industry standard technique, the Company should 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. I demonstrate, based on numerical examples, and actual operating data, that this method is more accurate than the Company's approach. The value of this adjustment is shown as item 21 on Table 1.

15. GRID allows duct firing to operate when the Combustion Turbines and Heat Recovery Steam Generator capacity of the facility is operating at minimum loadings. This is an unrealistic and inefficient mode of operation. These adjustments are shown on Table 1 as items 19 and 20.

<u>Transmission Modeling Issues</u>

16. Pursuant to the Commission Order in Docket No. 07-035-93, the Company now includes non-firm third party transmission in GRID. However, the average non-firm transmission energy in GRID is well below actual historical levels. Further, the Company uses substantial amounts of transmission capacity from PacifiCorp Transmission ("PacTran"). I recommend continued monitoring of these issues.

17. In Docket 07-035-93, the Commission ordered the Company to model non-firm transmission in a manner consistent with its market cap modeling. However, the Company did not do so. Rather it uses a four year average for non-firm transmission, but bases market caps on a single year of data. I propose to correct this mismatch, resulting in the adjustment shown on Table 1 as item 22.

18. The Company has included $13.0 million in costs (Total Company) related to short-term firm ("STF") transmission in GRID, but has only included a fraction of the STF transmission capacity in the model. I recommend the Commission require the Company to include all STF transmission capacity in GRID, resulting in the adjustment shown as item 23 on Table 1.

Other NPC Adjustments

19. I recommend the Company continue to reflect the benefit of transmission imbalance charges collected by the Company, which provides a source of below market energy. This is shown as item 30 on Table 1.

20. The Company has reduced the nameplate capacity of Cholla by 3 MW to reflect firm transmission constraints. However, Cholla's capacity is derated well below the nameplate level (and below the transmission limit) more than 80% of the time. As these derations are already factored into the outage rates, this amounts to a "double count" of the capacity reductions due to the transmission constraint. This is shown as item 32 on Table 1.

21. The Company continues to reflect reserve carrying requirements for the West Valley units in GRID, even though it no longer leases these facilities. This adjustment is shown as item 28 on Table 1.

22. The Company made an error in copying the non-owned reserve requirements from its workpapers to GRID. The correction to this error is shown at item 27 on Table 1.

23. The Company has "double counted" the reserve requirements of US Magnesium in the GRID model. The correction to this error is shown as item 29 on Table 1.

24. Finally, there is a small adjustment related to the balancing impact of the above adjustments, shown as item 31 on Table 1.

<u>PART 2: WIND RESOURCE ISSUES</u>

<u>Rolling Hills Prudence</u>

1. **The Rolling Hills project fails to meet the prudence standard. The project was developed at an inferior site and was sized at 99 MW simply to circumvent competitive bidding requirements. The project was developed by the Company after it was determined Begin Confidential……………………………………………………………… ………………………………………………………………………… End Confidential.**

   By September, 2007, Begin Confidential……………………………………………………………… ………………………………………………………………………… ………………………………………………………………………… ………………………………………………………………………… ………………………………………………………………………… ………………………………………………………………………… ………………………………………………………………………… ………………………………………………………………………… ………………………………………………………………………… ………………………………………………………………………… ………………………………………………………………………… ………………………………………………………………………… ………………………………………………………………………… ………………………………………………………………………… ………………………………………………………………………… End Confidential

   With this new analysis in hand, the Company immediately filed its Industrial Siting Application followed shortly by the CCN application in Wyoming. The CCN application stated that "*Studies completed by the Company's consultants indicate the site is suitable for a wind project.*"[1] However, the data supporting the project was characterized by its authors as only a "Begin Confidential ………………………………………………………………………… ………………… End Confidential. This doesn't represent the quality of information necessary to support a $200 million investment.

[1] CCN Application, Tallman Direct Testimony page 7.

More recent studies performed for the Company show some improvement in the Rolling Hills capacity factor forecast. Begin Confidential………………………………………………………………….. ………………………………………………………………………………… ………………………………………………………………………………… ………….End Confidential. Thus, the new wind studies provide little meaningful data for the Commission to rely upon.

A further problem with the Rolling Hills project is that it is expected to degrade the performance of the Glenrock project, which is downwind but at higher elevation.

One solution to the Rolling Hills issue would be use of a guaranteed capacity factor.[2] Absent a guaranteed capacity factor for Rolling Hills, I recommend the Commission remove the project from rate base and remove its generation from GRID. This adjustment would reduce Utah allocated revenue requirements overall, but increase NPC in GRID. These adjustments are shown on Table 1.

When confronted with essentially the same facts, the Oregon Public Utilities Commission ("OPUC") invoked the disallowance for Rolling Hills that I am recommending in this case.

<u>Glenrock Capacity Factor</u>

2. I also recommend the Commission impute a higher capacity factor for the Glenrock project to compensate for the degradation caused by Rolling Hills. This adjustment should be reflected in GRID.

<u>99 MW Wind Projects and Competitive Bidding Rules</u>

3. The Company sized the Glenrock, Rolling Hills and Seven Mile Hill projects at 99 MW to circumvent competitive bidding requirements in Utah and Oregon. However, they later developed these sites to more than 99 MW of capacity. The Utah legislature has since amended the 100 MW competitive bidding requirement. However, this issue has a bearing on Rolling Hills's prudence and should be considered by the Commission as it undermines confidence in the competitive bidding process.

[2] The general concept of guaranteeing wind project capacity factors has previously been opposed by the Company and was not adopted by the Commission in Docket 07-035-93. In OPUC Docket UE 200, the application of the concept to Rolling Hills was also opposed by the Company and not accepted by regulators. However, the Committee remains open to considering this approach.

Table 1
Summary of Recommended Adjustments - $

	Total Company	Est. Utah Jurisdiction
	SE	39.94%
	SG	40.33%
I. GRID (Net Variable Power Cost Issues)		
PacifiCorp Request NPC - GND-1SS	1,053,297,584	
A. GRID Commitment Logic - Screens	-$8,950,598	-$3,592,219
1 Reverse Company Screens	12,432,990	4,989,838
2 Gadsby Steam Screen	(499,469)	(200,456)
3 Gadsby CT Screen	(846,862)	(339,878)
4 Curant Creek Screen	(9,485,021)	(3,806,704)
5 Lake Side Screen	(5,713,741)	(2,293,144)
6 Chehalis Screen	(1,940,649)	(778,857)
7 Start Up Fuel Costs	(2,771,591)	(1,112,346)
8 Call Option Screen	(126,255)	(50,671)
B. LTF Contract Adjustments	(9,500,186)	(3,812,790)
9 Black Hills Power	(1,629,285)	(653,895)
10 PSCO	(2,032,391)	(815,677)
11 Sierra Pacific	(319,184)	(128,101)
12 UMPA II	(337,128)	(135,303)
13 Grant Reasonable Contract Error	(202,760)	(81,376)
14 QF Modeling Errors	(1,006,974)	(404,137)
15 SMUD Contract Imputed Price	(3,472,464)	(1,393,633)
16 Biomass Contract	(500,000)	(200,669)
C. Planned Outage Schedule		
17 Planned Outage Schedule	(4,077,484)	(1,636,451)
D. Outage Rate Modeling		
18 Outage Rate Adjustments	(981,158)	(393,776)
E. Generating Unit Representation in GRID		
19 Currant Creek Duct Firing Adjustment	(3,596,734)	(1,443,508)
20 Lake Side Duct Firing Adjustment	(1,011,553)	(405,975)
21 Heat Rate/Minimum Loading Deration Adjustment	(5,165,667)	(2,073,181)
F. Transmission Modeling		-
22 Non Firm Transmission modeling	923,031	370,448
23 Short Term Firm Transmission	(8,983,141)	(3,605,280)
G. Other NPC Adjustments		
24 Glenrock Capacity Factor	(390,135)	(156,576)
25 Remove Rolling Hills	12,433,860	4,990,187
26 Cholla Capacity	(790,679)	(317,330)
27 Reserve Modeling Error	(83,304)	(33,433)
28 West Valley Reserves	(460,501)	(184,817)
29 US Magnesium Reserves	(168,913)	(67,791)
30 Transmission Imbalance	(1,781,716)	(715,071)
Subtotal Power Cost Adjustments -	(32,584,875)	(13,077,565)
31 Additional Balancing Impact all above Adj.	56,694	22,754
Final Adjustment	(32,528,181)	(13,054,811)
Allowed - Final GRID Result*	1,020,769,403	
II. Renewable Resource Issues		
32 Rolling Hills Disallowance	(21,897,964)	(8,830,945)
Total Adjustments	(54,482,839)	(21,908,510)

II. PART 1. GRID ISSUES - DECEMBER UPDATE

Q. COMMENT ON THE COMPANY'S DECEMBER 8, 2008 GRID UPDATE.

A. The Company acknowledged shortly after it made its filing that there were a number of errors in the GRID model. See Exhibit CCS 4.2, a copy of the December response to MDR 1.8. I believe I have incorporated corrections to the most significant errors in my other adjustments.

III. COMMITMENT LOGIC ISSUE

Q. WHAT IS THE PURPOSE OF GRID?

A. The purpose of the GRID model is to estimate NPC 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)[3]

The above stated description is typical of mainstream utility production cost models. Such models assume system operating costs are minimized subject to operational constraints, such as transmission limitations. Simulation of the "least

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

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 ACTUALLY ACCOMPLISH ITS GOAL OF SIMULATING COST MINIMIZATION GIVEN THE SYSTEM CONFIGURATION IT MODELS?

A. No. Absent user supplied workarounds, GRID frequently fails to develop the least cost operation of resources. Left alone, there are thousands of hours per year when gas-fired generators fail to operate economically within the model. This has a spillover effect on coal-fired generation because the uneconomic operation of gas plants forces lower cost coal units to have their output curtailed.

The problem occurs because the logic in GRID separates the decision to commit (start up or to not shut down) a resource from the operating constraints (transmission and market capacity limits) imposed by model inputs. However, these operating constraints are used later to determine the optimal dispatch of resources. The model unrealistically assumes there is always a market for energy when making the commitment decision, but once the units are running frequently it assumes there is no market for the energy these resources produce.

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

A. Yes. However, the problem has recently been exacerbated by load growth (resulting in increasing constraints on the system) and the addition of various resources on the system including certain call options and combined cycle plants.

Q. HAS THE COMPANY ACKNOWLEDGED THIS PROBLEM?

A. Yes. In the prior general rate case (Docket No. 07-035-93) Mr. Duvall testified:

> The Company agrees that GRID should simulate normal prudent operation of the system. Absent unusual circumstances, the

Company would not run its gas units in a manner that would cause its less expensive coal plants to back down. To the extent that GRID systematically dispatches resources in this manner, the Company agrees that the model needs to be adjusted.

* * *

Q. How has the Company addressed this issue to date?

A. The Company has addressed this issue in two ways. First, when it has become clear that the model is systematically dispatching units in an uneconomic manner, the Company has applied manual workarounds (i.e. turning off the ability of the model to dispatch a certain unit at a certain time). Second, the Company has worked to refine and improve GRID's commitment logic in the last two upgrades to the model to eliminate the need for such manual workarounds.

Q. Has the most recent version of GRID completely resolved this issue?

A. No. The most recent version of GRID addresses and ameliorates the issue but did not resolve it in all cases.

Q. How does the Company propose to address this issue in this case?

A. The Company agrees that a manual workaround should be applied to prevent systematic uneconomic dispatch of the West Valley, Currant Creek and Lake Side plants[4]. [end quote]

In the prior case, Mr. Duvall agreed that GRID contained errors that overstated net power costs by $18 million on a total Company basis. However, the Commission agreed with the Committee's proposed adjustment that increased the amount of the correction for uneconomic generation in GRID in its final order in Docket 07-035-93.

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4 Re Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates, Utah Public Service Commission Docket No. 07-035-93, at 15-16. (Rebuttal Testimony of Gregory N. Duvall).

Q. HAS THE COMPANY ATTEMPTED TO ADDRESS THIS PROBLEM IN ITS DECEMBER 8, 2008 FILING?

A. Yes. Mr. Duvall testified as follows:

> *From its original filing in this case, the Company has taken steps to ensure that there is no uneconomic dispatch of resources in its net power costs model on a monthly basis.* Once all other inputs have been set, final net power costs are determined after a series of GRID runs to screen out the uneconomic commitment of gas-fired plants. The screens are set in a way to block the gas-fired plants from being committed to run if they displace less expensive resources when running. The screens are set for the Currant Creek, Lake Side and Chehalis plants. (Second Supplemental Direct Testimony of Gregory N. Duvall December 8, 2008 page 23, emphasis added.)

Q. PLEASE COMMENT ON MR. DUVALL'S TESTIMONY AND THE ADJUSTMENTS THE COMPANY MADE IN GRID.

A. I've reviewed the manual workarounds[5] the Company has developed and I'm glad to see the Company has now adopted a more rigorous methodology for computing the screens.[6] However, the Company's approach, while an improvement falls somewhat short of the goal of eliminating uneconomic generation in GRID.

Q. WHAT ARE THE SHORTCOMINGS IN THE COMPANY'S APPROACH?

A. There are three fundamental problems. First, the screens used by the Company do not eliminate *all* of the uneconomic generation in GRID. Second, they are based on a *monthly* analysis, which fails to identify specific days when the gas units should or shouldn't be shut down. It is important to realize that in the field, the decision to start up, or shut down a cycling unit is made on a *daily rather than*

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[5] Subsequently referred to as "screens".

[6] This is the first time (in Utah or any state) the Company has actually performed its own analysis of this modeling problem and developed screens using an analysis of hourly costs. In prior instances, the Company has generally developed screens using a more subjective, and judgmental approach. Typically, the Company used screens I developed but made unsupported adjustments to them.

monthly basis. Finally, the Company has not applied a rigorous method to all gas plants. As a result, the Company's proposed screens don't achieve the goal of ensuring there is no uneconomic generation in GRID.

Q. HOW DO THE COMPANY SUPPLIED SCREENS COMPARE TO THOSE APPROVED IN DOCKET 07-093-35?

A. In Docket No. 07-035-93, the Commission adopted the screens I proposed for the gas fired units and call options. Those screens relied upon both a daily and monthly analysis of uneconomic generation within GRID. I recommend the Commission continue to strive for a solution to this problem that eliminates as much uneconomic generation as practical. The Company's method is a short cut that simply isn't necessary, and which rewards the Company for the uncorrected error in GRID.

Q. CAN YOU EXPLAIN SOME OF THE PROBLEMS WITH THE COMPANY SCREENS?

A. The most serious problem is that the Company isn't considering the impact of start up costs on the daily decision to start or shut down the combined cycle plants. In the Company approach, it is first determined whether a screen should be applied in a specific month. If so, then the combined cycle plants are shut down every single night of the month (and then allowed to restart the next day), irrespective of economics for any particular day. A number of problems are present in the Company's modeling. First, this method may allow the units to run all nights when it does not make sense to do so simply because there are more days in a particular month when it is better to keep the units running than to shut them down. For example, there may be times when it is better to shut down the combined cycle units on weekends or holidays, rather than allow them to run as dictated by the model. Second, units may actually be *required* to shut down by the Company's screens at times when they should have been allowed to run. This could happen if there are specific days within a month where operating the combined cycle plants produces a large benefit, even if there are many more days during that month when the units should be required to shut down. Third, the model may allow a unit to run on days when it otherwise shouldn't. Finally, the Company does no rigorous analysis of the days or hours when the Gadsby peaking units should be prevented from running.

Q. SHOULD START UP COSTS PLAY A ROLE IN THIS PROCESS?

A. Yes. Based on the GRID inputs and workpapers, the cost of starting up a combined cycle plant is around XXXXX per day. As a result, unless shutting down the plant at night saves at least that much, it should be allowed to keep running. Conversely, there may be days when units shouldn't be running at all because it doesn't produce XXXXXX in dispatch benefits. Unfortunately, the method used by the Company tends to create more starts and stops of the combined cycle units than is justified by economics and thereby overstates start up costs. This is important because the Company is now including start up costs as part of its overall NPC.

Q. IS PROPERLY INCORPORATING START UP COSTS INTO GRID A REASONABLE REQUIREMENT?

A. Yes. First, in the "real world" start up costs are an important factor considered in daily commitment decisions. The model should not ignore actual practice. *Second, the model already includes start up cost inputs because it was always* *intended to make the right start up and shut down decisions considering these costs.* Simply because the model is failing to operate correctly, does not mean we should ignore the problem. The methodology I propose is intended to provide a better solution to the uneconomic dispatch problem in order to address the shortcomings in the Company methodology.

Q. DESCRIBE THE METHODOLOGY YOU PROPOSE.

A. The proposed methodology is essentially the same as the Company's, but it also includes the start up costs and determines on a daily (rather than monthly) basis whether the resources should be shut down at night or allowed to run. It also considers whether the resource should be running at all each day. A screen is therefore computed for each day, requiring shut downs (or not) as necessary, while attempting to develop the optimal schedule for each day. The analysis could encompass up to 365 different screens for each unit during the year. As a practical matter, there are many days when no screen is required at all. The final result is far fewer start ups for combined cycle plants than assumed by the Company because some shut downs were not required, and some start ups weren't economically justified.

Q. DOES IT POSE AN UNREASONABLE BURDEN ON THE COMPANY TO HAVE TO DEVELOP UP TO 365 SCREENS FOR EACH COMBINED CYCLE UNIT IN GRID?

A. No. The process for developing the screens requires the same number of GRID runs, and basically the same analysis as performed by the Company. The development of the daily screens can easily be "automated" to provide the GRID inputs. This is the only way to achieve the elimination of all uneconomic generation in GRID. I don’t believe this approach takes appreciably more time than the Company’s method.

In the end, this entire process is nothing more (or less) than what the GRID model is already attempting to do, and should be doing correctly. GRID is trying to decide which days each unit should be started up, and how long they should run, if at all. GRID by itself is not starting all of these units every single day. However, all too often, the model fails to determine the correct days and hours when the various units should be running. The Company’s simplified screening process fails to achieve the most optimal solution to the problem.

Q. IS IT IMPORTANT TO DEVELOP THE OPTIMAL SCREENS FOR GRID ON A SEQUENTIAL BASIS?

A. Yes. There is some interaction between the level of constraints on the system, and the operation of other resources. As a result, it is not really proper to develop screens in isolation from each other. To address this problem, I developed the screen I used sequentially, starting with Gadsby and going through the combined cycle units.

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. The first step (item 1) reverses the screens used by the Company. I next implement adjustments for the optimized screens for all of the Company’s gas units (items 2-6).

Because my screens result in fewer start ups than the Company screens, there is a reduction in the amount of incremental start up fuel and O&M expenses resulting from daily cycling of the combined cycle units. This impact is factored into the overall impact of each adjustment.

Q. DO YOU BELIEVE YOU HAVE DEVELOPED THE MOST OPTIMAL SCREENS FOR USE IN GRID?

A. Unfortunately not, because of the complexity of this problem. There may be days when the screens I selected could have been improved slightly. However, the screens I propose do a significantly better job of reducing uneconomic operation of gas-fired plants than those proposed by the Company. It is important for the Commission to realize that any uneconomic generation in the model produces higher power cost recovery for the Company than is justified.

Q. ARE THERE OTHER PROBLEMS WITH THE START UP COSTS USED BY THE COMPANY IN ITS ANALYSIS?

A. Yes. The start up fuel costs used by the GRID model only considers the amount of fuel required to take the unit from a warm shut-down state to minimum load. However, during the period the units are ramping up (about 2 hours), the power output of these units is gradually increasing. In Docket No. 07-035-93, the Company produced workpapers showing development of the start up fuel (See attachment CCS 7.16(b) from that case, Exhibit CCS 4.3). That analysis recognized the market value of start up energy. I requested comparable workpapers in this case, but the Company wouldn't provide them. In CCS 21.14 (Exhibit CCS 4.4) the Company indicated it did not consider the value of start up energy to be substantial, and suggested that when combined cycle units are being started up, it would likely result in coal-fired plants being backed down.

Q. WHAT IS YOUR RECOMMENDATION?

A. At a minimum, the Commission should recognize the value of start up energy for combined cycle plants at the cost of coal-fired generation (approximately $13/MWh) in GRID. This is substantially less than the Company assumed in the prior case ($50/MWh, as is shown on Exhibit CCS 4.3) and is a reasonable lower limit value. The energy generated by units during the startup sequence has to go somewhere, and coal is the lowest priced fuel on the system. As a result, I recommend the Commission adopt adjustment 7 shown on Table 1 to implement this correction. Note that this adjustment should be adopted independent of whether the Commission adopts my recommended screens or the Company's screens. However, the screens I use produce fewer starts for the combined cycle plants, than the Company assumes. The figures shown on line 7 on Table 1 are based on my calculation of the number of starts. If the Company's proposed screens are used, there are more starts and the value of the adjustment increases to $3.7 million on a total Company basis, or $1.49 million for Utah.

IV. CONTRACT MODELING IN GRID

Q. DOES GRID MODEL PURCHASE AND SALES 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 NPC. I will discuss issues related to certain of PacifiCorp's long-term contracts.

CALL OPTION PURCHASE CONTRACTS

Q. WHAT IS A CALL OPTION CONTRACT?

A. These are contracts that allow the purchaser the right to pre-schedule energy deliveries based on expected market prices and/or the purchasers' requirements. The Company is both a buyer and seller of call option contracts.

Q. WERE CALL OPTIONS ADDRESSED IN DOCKET 07-035-93?

A. Yes. The Commission addressed the uneconomic dispatch problem as it pertained to call option purchase contracts modeled in GRID. The Company has employed a monthly screen for modeling these contracts. However, the Commission order in the last case adopted my proposed methodology, which was based on a daily screen. Because these options can be scheduled on a daily basis rather than monthly basis, use of a daily screen is more appropriate and certainly feasible within the terms of the call option contract. In this case, there is only one such contract requiring correction. I have corrected the Company's proposed screen to reflect a daily scheduling of Morgan Stanley contract 272158. The impact of this adjustment is shown as adjustment 8 on Table 1.

CALL OPTION SALE CONTRACT MODELING

Q. IS THE CALL OPTION PURCHASE DISCUSSED ABOVE THE ONLY CALL OPTION MODELED IN GRID?

A. No. The Company models "call option sales" for the Sacramento Municipal Utility District ("SMUD"), Black Hills Power ("BHP"), Public Service Colorado ("PSCO"), Sierra Pacific ("SPP") and Utah Municipal Power Agency II ("UMPA II").

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

A. In GRID, inputs specify contractual energy limits on an hourly, daily, weekly, monthly or annual basis. For sales with annual contract energy limits, such as

SMUD, GRID schedules the contract energy during the highest cost hours of the year. Since the contract has an annual energy limit of approximately 350,400 MWh (with a 100 MW maximum hourly take), this means absent intervention, GRID assumes SMUD will call the energy from the contract during the highest cost[7] 3504 hours[8] in the year. As a result, GRID would assume no energy would be requested by SMUD during the low cost months from April to June. For SMUD, and all other call option sales contracts, GRID would assume the counterparty finds the most costly way possible to use the energy available from the Company. In effect, the Company's modeling assumes a "worst case scenario" for these kinds of sales contracts.

Q. IS THIS REALISTIC?

A. Not based on historical data. Generally, counterparties use these resources in a less costly manner than assumed by the Company. There are many reasons why counterparties may not utilize call options in the most disadvantageous manner as assumed by the Company. The counterparty is not using the same forward price curves as the Company. The counterparty really has no knowledge of the Company's forward price curves and may not even face the same forward prices as the Company does. Differences in delivery location, transmission constraints, availability of the counterparties' own generation and many other factors will drive decisions to use the available energy. In the end, the counterparty is interested in serving its own customers at the least possible cost (subject to its

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[7] Based on COB market prices.

[8] 350,400/100= 3504.

own constraints), not in maximizing the cost in a totally unconstrained manner to PacifiCorp.

Q. IN DOCKET 07-035-93, YOU PROPOSED AN ADJUSTMENT FOR THE SMUD CONTRACT. HOW DID THE COMMISSION DECIDE THIS ISSUE?

A. The Commission accepted my proposal to base the energy utilization of the SMUD contract on historical patterns, rather than purely based on the model's unconstrained optimization result. The Commission also declined to act on the Company's request for reconsideration on the matter.

Q. HAS THE COMPANY ACCEPTED THE COMMISSION ORDERED METHODOLOGY IN THIS CASE?

A. Yes, though the Company still disagrees with the method. The Company has made a number of different arguments. For example, Mr. Duvall has argued it is unfair to simply look at one contract without looking at all similar contracts. In response to CCS 16.31, Mr. Duvall indicated one should look at all dispatchable contracts, whether purchases or sales. (Dispatchable contracts are essentially the same as call option contracts.) In his December testimony, Mr. Duvall seemed to suggest that if it were correct to not "optimize" sales contracts, one should also not optimize purchase agreements such as the Hermiston purchase.

Q. DO YOU AGREE?

A. No. I have analyzed all call option sales contracts to see if the counterparty is using the energy as assumed by the Company. Based on Mr. Duvall's reasoning, one would not make any adjustment to the modeling of SMUD unless one also based the dispatch of the Hermiston purchase on the historical pattern of delivery from the unit. However, the Hermiston purchase is an inseparable part of the

Hermiston plant and cannot be dispatched apart from the rest of the plant. The Company owned share, and the purchased share are both under the Company's control. The Company decides when to use, and when not to use the resource and it does so in order to minimize costs, subject to the constraints the Company is facing.

Further, the modeling of call option purchases in GRID illustrates another problem with Mr. Duvall's reasoning, and shows why a simple review of unconstrained forward prices as compared to a contracts strike price is unrealistic. As we know, absent screens, GRID can incorrectly dispatch call option purchase energy based solely on market prices. We also know that this procedure is erroneous because it ignores operational and market constraints. That's why the Commission ordered, and the Company agreed to use, screens for the call option purchases in Docket No. 07-035-93. The simplistic matching of contract prices, forward prices, and available energy for these contracts is already known to produce the wrong answer for PacifiCorp's own call option purchases. The same is likely to be true for counterparties taking a call option sale from PacifiCorp. The real problem with the Company's modeling is that while GRID may "know" the constraints and forward prices PacifiCorp experiences, it knows nothing about the forward prices or constraints that SMUD or the other counterparties expect to occur. As a result, GRID cannot really simulate the counterparty's utilization of dispatchable energy provided by the Company. Unless GRID were to simulate the entire western GRID and all associated constraints, and used counterparty's forward price curves, the model cannot realistically dispatch call option sales to a third party. In many respects, the use of historical data for call option sale modeling is a logical extension of the use of screens for call option purchases. Both stem from recognition of the model's failure to perform a realistic optimization in the face of constraints. In the case of purchases, the Company's constraints are known within the model. In the case of sales, the counterparties constraints are unknown in the model.

Q. DID YOU LOOK AT CONTRACTS OTHER THAN SMUD?

A. Yes. I examined the actual usage patterns of all call option sales contracts in GRID: SMUD, BHP, PSCO, SPP, and UMPA II. In general, these contracts have a much flatter profile than the Company assumes resulting in less on peak energy being required, and more off-peak energy being used. Exhibit CCS 4.5 shows the actual patterns for these contracts based on historical data as compared with GRID. To address this problem, I have therefore modeled these contracts in a manner that better reflects historical delivery patterns. For the Black Hills contract it made more sense to model it as a "flat contract", while the other contracts were modeled as having non-zero hourly minimum demands. Items 9-12 on Table 1 show the value of the adjustment for each of these contracts.

SMUD CONTRACT PRICING

Q. ARE THERE ANY OTHER ISSUES RELATED TO SMUD?

A. The Commission has imputed a price to the SMUD contract of $37/MWh since the 1999 general rate case, Docket 99-035-10. The SMUD contract has been an issue in every case since that time, though most were settled, and there was no decision on the matter until Docket 07-035-93. Since the time of the original development of the $37/MWh price, the cost of serving SMUD has increased dramatically while the revenue paid to the Company by SMUD has increased as well (from $14.66/MWh in 1999 to 21.46/MWh in 2008). In the end, the Company's SMUD disallowance has shrunk while the subsidy provided by the Company's customers to SMUD has grown substantially. As a matter of fairness, I believe the SMUD imputed price should be reset and indexed to the actual contract price, and should be set to recognize all revenue elements associated with the contract.

The SMUD contract pricing issue was a significant matter in Docket No. 07-035-93. While the Commission initially adopted a substantial increase to the SMUD imputed price, on reconsideration, it decided to retain the $37/MWh. However, the Commission discussed the reasons for changing its position, and suggested a proper method for determining the overall level of the SMUD imputed prices:

"Our application of an imputed price of $58.46 for the SMUD contract in this case was not due to a calculation error. The $58.46 price is based upon our application of a method presented in the pre-filed Surrebuttal testimony of the Division. The Division's written testimony presented this method as a reasonableness test for any proposed imputation. This method accounted for the lump-sum payment only. Effectively, the Division concluded that the lump-sum payment was the only value that should be recognized for the SMUD contract. Based on this view, the Division abandoned its support of its previously presented adjustment and ultimately advocated adoption of a $37 imputation price for the SMUD contract advocated by the Company. In reviewing and evaluating the alternative methods and reasoning ultimately advocated by the parties for their competing adjustments, we believed the Division's method represented a reasonable, although incomplete, approach through which to address the matter. We disagreed with the Division that only the lump-sum payment should be considered. *Value from the SMUD contract should include recognition of all of the components received by the Company in exchange for the provision of power*." (Order on Reconsideration, Docket No. 07-035-93, pages 8-9, emphasis added.)

Q. PLEASE STATE YOUR UNDERSTANDING OF WHAT THE COMMISSION WAS LOOKING FOR IN THAT PASSAGE.

A. The SMUD contract had two components: an up front payment of $94 million, and an energy charge which is recomputed each year based on the average production cost of the Jim Bridger unit. The Commission appears to be seeking a method for computing the imputed price that gives recognition to both components of revenue received by the Company. The problem with the record in the prior case was that the Division calculations appear to have overstated the component necessary for recovery of the $94 million payment. When added to the current contract price, it did produce a figure that was too high.

Q. HOW WOULD YOU DETERMINE THE IMPUTED PRICE?

A. To provide recovery of both components of the SMUD contract, it makes sense to assume the up-front payment was recovered over the term of the contract and then add that to the current contract revenues. Based on Exhibit GND-3SS, a constant, per kWh charge, recovery of the up front payment would require an additional $24.9/MWh be added to the contract revenue. Adding this amount to the current contract price ($22.0/MWh) would produce an imputed price of $46.9/MWh, resulting in an adjustment in the amount shown as item 15 on Table 1. I also recommend this amount be updated each year based on the projected SMUD contract price for the test year.

QF AND OTHER CONTRACT INPUT ERRORS

Q. WERE THERE ERRORS IN ANY WHOLESALE CONTRACT INPUTS USED BY THE COMPANY?

A. Yes. There were three errors in the Company's filing related to QF contracts. The Douglas County Forest Products project and the Kennecott QF have overstated energy production and the energy prices assumed for new Oregon wind farms are also overstated. I've corrected these inputs to GRID, resulting in the adjustment shown on Table 1 as item 14. As discussed above, the Company acknowledged these errors in MDR 1.8.

There was also an error in the computation of revenues provided by the Company's Grant Reasonable contract entitlement. The Company computed the revenue stream based on a November 13, 2008 forward price curve. It is unclear why the Company used this forward price curve, but the Company used the November 4, 2008 forward price curve for all of its other adjustments, and it should be used for this contract as well. Item 13 on Table 1 reflects this correction.

BIOMASS CONTRACT

Q. DID THE COMMISSION MAKE AN ADJUSTMENT RELATED TO THE BIOMASS PROJECT IN DOCKET 07-035-93?

A. Yes. Committee witness Philip Hayet testified that the Company had entered into non-generation agreements with this QF every year from 2005 to 2007. Under those agreements, the counterparty received a payment to shut down during some low market price months. During those periods, the avoided cost to PacifiCorp for replacement power was apparently below the counterparty's incremental cost of production. As a result, a shut down during those periods was a win-win for the Company and for Biomass. In 2008, the Company entered into another non-generation agreement.[9] The Company acknowledged the new non-generation contract in its rebuttal testimony in the last case and the Commission adopted an adjustment. Because the Company has now entered into non-generation agreements with Biomass for four years in a row, such an agreement should be factored into the test year to provide a proper normalization. I recommend the Commission implement this adjustment. An estimate for the impact of this adjustment is shown on Table 1, as item 16.

Q. DOES THIS CONSTITUTE AN UPDATE, OR NEW INFORMATION?

A. No. The Company has negotiated a non-generation agreement with Biomass for four years in a row. Irrespective of what happens in 2009, negotiation of such an agreement should be considered as a normal practice of the Company. If the Company does enter into such an agreement before its rebuttal filing, I recommend that contract be modeled. Otherwise, the adjustment should be based on historical relationships.

V. PLANNED OUTAGE SCHEDULE

Q. WHAT ARE PLANNED OUTAGES?

A. Planned outages represent events when generators are taken out of service for routine scheduled repairs and maintenance. Plants are typically taken down once per year for scheduled work, while individual units may only be taken down once every four years. During the on-site interviews I conducted on February 15, 2008 in Docket 07-035-93, I learned this work is normally scheduled in the spring

[9] This was unknown by Mr. Hayet at the time his testimony was filed.

when demand and market prices are at their lowest levels. This makes perfect sense and constitutes a prudent, cost minimizing practice by the Company.

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

A. No. The Company uses an assumed 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, use of a normalized maintenance schedule is reasonable. However, I do not believe that the schedule input assumptions used in GRID are a reasonable representation of a normalized outage schedule, as is illustrated in the chart below.

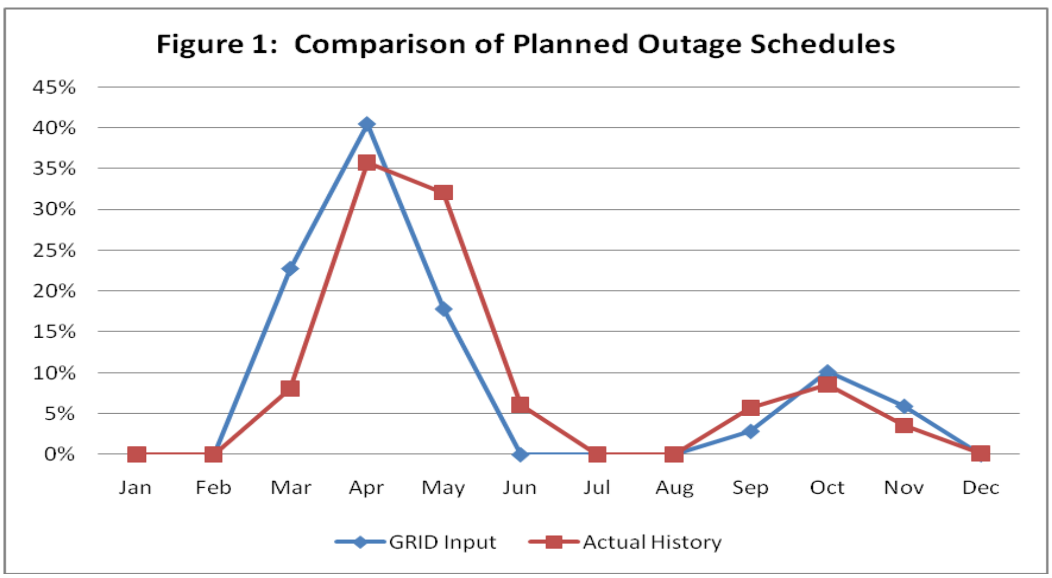

Figure 1: Comparison of Planned Outage Schedules

Q. PLEASE EXPLAIN THIS FIGURE.

A. This graph shows the historical percentage of scheduled coal outage energy[10] for each month of the calendar year due to planned outages based on the 48-month period ended June 30, 2008.[11] 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. April, May and June typically have the lowest market prices, and the Company traditionally has scheduled 74% of its maintenance during these months. The Company's assumed planned outage schedule concentrates more of the planned outage energy in March and April, with none in June. Essentially, the Company assumptions move outages further forward in the year than in actual practice.

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 does not appear to be based on historical or expected outage schedules, market price curves or other scheduling considerations. Rather, the Company simply makes assumptions about when a few outages will occur, and then keys other outages off of those assumed dates. The Company's method is opaque, and subjective. As we saw in Docket No. 07-035-93, the Company's method can produce substantially different outage schedules, all the while arguably applying the "same methodology." In that case, initially the Company's

[10] 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. Because gas fired peaking units have much higher operating costs, and are frequently shut down the schedule of these kinds of plants is not as significant.

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

method produced coal plant outages starting in January and February, while subsequent schedules used in the rebuttal phase removed some of those winter outages. The Company's "method" however never really changed, just some of the driving inputs. Ultimately the Commission rejected the Company's schedule in favor of a schedule based on tracking historic outage scheduling patterns. While the Company's schedule in this case is more realistic than that presented initially in the prior case, it still tends to overstate planned outage costs because it assumes they occur earlier in the year than dictated by actual practice.

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

A. I believe there is a very simple resolution to the matter. The Company bases its normalized outage energy requirements on the most recent four years of historical data (the 48 months ending June 30, 2008). The normalized schedule adopted should reflect the actual schedules used in that same period. This was the basis for the outage schedule the Commission adopted in the last case.

One approach would be to apply each of the four actual schedules used during the four-year period in GRID. To do this one would analyze four distinct outage schedules for the one-year periods starting from July 2004 to June 2008. By computing the average cost of actual outages over the four-year period it would be possible to develop a power cost study that provides realistic normalized planned outages. I used this method in the rebuttal phase of Docket 07-035-93 to verify the reasonableness of the single outage schedule I proposed. I also proposed this method in Oregon Docket UE 199, conducted last year.

Q. DID THE COMPANY HAVE ANY CRITICISMS OF THE USE OF FOUR ACTUAL PLANNED OUTAGE SCHEDULES IN THE RECENT OREGON CASE?

A. The most significant complaint the Company raised was the adoption of this methodology would be difficult since it requires multiple GRID runs. This could therefore, complicate development of screens, and other adjustments. While the impact on screens is not substantial, the use of four actual schedules as opposed to one normalized schedule is more cumbersome. To address this concern, I have also developed a single schedule that uses all outages that occurred during the four year period, but reduces their duration to ¼ of the actual duration. The timing of each outage was then centered about the mid-point of the actual outage as it occurred during the four year period. This produces a single schedule which follows the historic pattern of outage scheduling, and which can be shown to produce results nearly identical to the four actual schedules. I then compared the results of the single schedule with the results from the four actual schedules to verify that the single schedule produces a result in line with the four actual schedules. In the end, the two approaches were in close agreement.

Q. ARE THERE OTHER ADVANTAGES TO THIS METHODOLOGY?

A. Yes. The use of the actual schedules is not subjective as compared to development of a schedule based on the Company's approach, or any other method. The data is readily available from MDR 2.57-2 and easy to apply and interpret. The number of outage days and outage energy is the same for the normalized schedules and the actual four-year average. As the four-year average underlies the Company's planned outage requirements, this is a logical extension of the Company's methodology, which has been accepted by the Commission for many years. Finally, because all four of these schedules were actually used by the Company, there is no basis to suggest they were "result oriented" (i.e., solely designed to align with low market prices) impractical, infeasible or otherwise improper. This proposal provides a transparent and realistic methodology for outage scheduling which I recommend the Commission adopt.

Q. WERE THERE ANY UNITS FOR WHICH THIS APPROACH COULD NOT BE APPLIED DIRECTLY?

A. Currant Creek and Lake Side were online for only part of the four-year period. The Company used both prior and projected outages of these plants to determine the annual outage requirement (number of days) for these units. Because the Company also has used and expects to use spring and fall outages for these plants, I used the Company's planned fall outage for Lake Side, and assumed a spring outage for Currant Creek.

Q. PLEASE DISCUSS THE RESULTS OF THIS ANALYSIS.

A. The table below presents these results. The figures shown are compared to the Company's original schedule. The results demonstrate that the Company has overstated the cost due to planned outages in GRID and that the single composite schedule produces results comparable to the average of the four individual schedules.

Table 2 – Planned Outage Schedule Adjustment

Planned Outage Scenario	GRID NPC	Change from Company Base	% Change	Planned Outage Energy (mWh)	Change mWh	Change %
Company Base	1,053,297,584			6,848,761		
2004-2005	1,040,410,071	(12,887,513)	-1.2%	6,393,476	-455,285	-6.6%
2005-2006	1,055,960,627	2,663,043	0.3%	7,118,887	270,126	3.9%
2006-2007	1,066,773,305	13,475,721	1.3%	7,373,112	524,351	7.7%
2007-2008	1,040,461,743	(12,835,841)	-1.2%	6,512,739	-336,022	-4.9%
Four Year Average	1,050,901,437	(2,396,148)	-0.2%	6,849,553	792	0.0%
GRID Using Composite Schedule	1,050,586,777	(2,710,807)	-0.3%	6,867,668		

Q. THE TOTAL NPC FIGURES SHOW A WIDE COST VARIATION DURING THE FOUR-YEAR PERIOD. PLEASE EXPLAIN.

A. Outages are scheduled on a cyclical basis and the costs during any single year will vary. The first and last years were periods where relatively few planned outages were scheduled. The third year was a high cost period which the table shows had more scheduled outages. This table actually provides a good reason for normalizing maintenance instead of using a single year. The results can vary substantially from one year to the next based on the actual outage schedule. This is why it is reasonable for the Company to use a four-year average to develop the amount of planned outage energy to include in the test year. I recommend the Commission adopt my proposed methodology for computing the planned outage schedule to be used in GRID. This adjustment is shown as item 17 on Table 1.

V. GRID HYDRO MODELING

Q. BRIEFLY EXPLAIN THE HYDRO MODELING METHOD USED IN GRID IN PRIOR FILINGS.

A. In the Company's earlier filings (July and September, as well as prior cases) GRID simulated three scenarios: Wet, Median and Dry ("WMD"). These were *assumed* by the Company to represent the 25th, 50th, and 75th percentiles of the annual hydro energy distribution. GRID computes power costs for each of these scenarios and takes the simple average of the three results to develop normalized net power costs.

Q. DID YOU OBJECT TO THE COMPANY'S MODELING APPROACH IN DOCKET NO. 07-035-93 AND IN PRIOR CASES?

A. Yes, this issue has been contested ever since the Company switched from multiple water-year modeling in the 2004 case. I have testified that the Company method overstates both the severity and likelihood of the "wet" and "dry" hydro scenarios modeled in GRID. I made certain recommendations in Docket 07-035-93, including use of the properly computed weights for the three scenarios, or use of the "median" scenario only. I ultimately requested the Commission require the Company to file a 40 water year study in subsequent cases to enable analysis of this issue.

Q. HOW IS THE COMPANY NOW TREATING THIS ISSUE?

A. In the December filing, Mr. Duvall testified that the Company was now using only the median hydro scenario in the 2009 Test Year GRID study, in order to "minimize controversy" in this proceeding.

Q. ARE YOU CONCERNED THAT USE OF A SINGLE HYDRO SCENARIO WILL MAKE GRID LESS REALISTIC?

A. Multiple water-year modeling is the "gold standard" for hydro dominant systems. However, because of the substantial growth in other kinds of resources, and the decline in production from PacifiCorp's hydro resources, PacifiCorp is no longer a hydro dominant system. Indeed, in 2009 the Company will obtain less than 10% of its requirements from hydro. As a result, there is probably less need for the Company to model hydro generation in a multiple scenario basis. However, the best way to test that assumption is to have a conventional 40 water year hydro study readily available to parties. The Commission required the Company to make such studies available upon request in Docket No. 07-035-93, and I recommend it continue to do so.

Q. DO YOU HAVE ANY CONCERNS REGARDING THE COMPANY'S SUDDEN CHANGE OF HEART CONCERNING THIS ISSUE?

A. I'm concerned that they may have done so only to gain a temporary advantage.[12] The Commission must ensure that the Company consistently uses a methodology and not allow them to choose whichever methodology benefits them on a case by case basis.

VI. THERMAL DERATION FACTORS

Q. EXPLAIN THE USE OF THERMAL DERATION FACTORS IN GRID.[13]

A. In GRID, thermal deration factors (also called unplanned outage rates) control the amount of generation available from thermal units. The more generation that is available, the lower net variable power costs will be. 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 DO YOU AGREE WITH THE COMPANY'S OUTAGE RATE INPUTS?

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12 Mr. Duvall acknowledges this use of Median hydro only increases NPC by something approaching $1 million on a total Company basis. See page 31 of the Second Supplemental Testimony of Gregory N. Duvall. It's unclear how he computed this because in the response to CCS 29.21 the Company refused to provide the wet and dry cases and stated "The requested forecasts were never prepared by the Company and do not exist."

13 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.

A. Yes, except for a few minor exceptions, which I'll discuss shortly. The Company has correctly implemented the Commission's order from Docket 07-035-93, requiring elimination of monthly outage rate modeling and use of a weekend, weekday split in the outage rates used.

The Company has also removed the lost energy[14] resulting from two outages (a November, 2006 outage at Bridger and an October, 2006 outage at Carbon). These outages were previously disallowed by the Oregon Public Utility Commission in Docket No. UE 191.

Q. DID THE COMPANY REMOVE ALL IMPRUDENT OUTAGES FROM GRID?

A. No. There were several other small outage events that occurred in late 2006 and 2007, whose prudence was litigated in the 2008 Wyoming PCAM proceeding. Through discovery requests in the Wyoming case, I obtained Root Cause Analysis ("RCA") reports prepared by the Company to determine the cause of these outages. The Company agreed to allow the Committee to use these documents, subject to protecting their confidentiality.

Q. HAVE YOU IDENTIFIED ANY OUTAGES THAT FAIL TO SATISFY THE PRUDENCE STANDARD?

A. Yes. The first such outage was a December 23, 2006 outage at Carbon 2. This event lasted 7 hours and resulted in 754 lost MWh. Begin Confidential ……………………………………………………………………………………… ………………………………………………………………………………………

[14] Lost energy is the amount of generation not available to the Company due to outages or durations. It is a direct input into the outage rate calculation.

……………………………………………………………………………………… ………End Confidential.

The second issue relates to a series of derations at Hunter 2 for SO3 system problems in December 2006. These events occurred over a period of several days and resulted in more than 7800 lost MWh. Begin Confidential……………………………………………………………………… ……………………………………………………………………………………… ……………………………………………………………………………………… ……………………………………………………………………………………… End Confidential.

The third event occurred in August, 2007. A lightening strike caused a trip of Naughton 2 resulting in a unit trip losing 963 MWh. While a lightening strike is not indicative of imprudence, the RCA noted that other avoidable factors were the root causes of the outage:

Begin Confidential" **…………………………………………………………………………………… …………………………………………………………………………………… ………………………*****End Confidential***" (Confidential Exhibit CCS 4.6c)

The RCA determined as follows:

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Another event occurred on October 16, 2007 at Naughton 3 related to an operator error. This event lasted about 4 hours and resulted in a loss of 1260 MWh. The RCA report for this event states as follows:

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On November 18, 2007 an event resulting in lost energy of 858 MWh took place at Naughton 3, clearly specified in the RCA as being due to XXXXXXXX XXX (Confidential Exhibit CCS 4.6e).

I recommend that all of the above events be removed from the outage rate calculations used in GRID, as they weren't prudent, and all were preventable.

Q. ARE THERE ANY OTHER OUTAGE ADJUSTMENTS YOU RECOMMEND?

A. Yes. On April 30, 2006 Currant Creek experienced a long (680 hour) outage due to a problem with the generator output breaker. Based on my review of the Root Cause Analysis report, I have not identified any prudence issue. However, the Company computed lost energy for the event based on the assumption that in the absence of the outage, the plant would have been running the entire 680 hour period fully loaded. This is a rather unlikely outcome because during the months of April (before the outage) and June, 2006 (after the outage) the plant was normally shut down at night. Review of data contained in MDR 2.57-2, shows that during April and June 2006, the plant was placed on reserve shutdown nearly half the time. As a result, the assumption that Currant Creek would have been running fully loaded during the outage period is unsupportable and overstates the outage rate for Currant Creek.

Q. HOW DO YOU RECOMMEND THIS EVENT BE TREATED IN GRID?

A. I recommend the Commission assume that Currant Creek was on reserve shutdown the same amount of time during the 680 hour period as it was in April and June 2006. This issue also illustrates a systematic problem with the Company's methodology for computing outage rates for cycling units, in that lost energy is likely overstated because reserve shutdowns aren't considered. These issues are now being investigated by the Oregon Public Utility Commission in Docket No. UM 1355. I recommend the Commission consider addressing such issue in future cases.

Q. ARE THERE ANY OTHER PROBLEMS WITH THE OUTAGE RATE MODELING IN GRID?

A, Yes. I noticed a discrepancy between the lost energy used by the Company in computation of outage rates in MDR 2.57-1, as compared to the underlying outage data contained in MDR 2.57-2. As a result, I adjusted the lost energy in the computation of the outage rates used in GRID. This had a small impact on the outage rates of Currant Creek and Gadsby. All of these outage rate adjustments are reflected in Table 1 as item 18.

Q. DO YOU HAVE ANY RECOMMENDATIONS CONCERNING THE ISSUE OF RAMPING?

A. Yes. The Company continues to include an adjustment for ramping in its modeling of outage rates in GRID. The Commission adopted a compromise position regarding ramping in Docket No. 07-035-93 but indicated a willingness to further consider the issue in future cases. In this case, the Company continues to apply the ramping methodology, though it did make a correction to the Cholla ramping adjustment, identified in CCS discovery request 20.5.

The workpapers supporting the ramping adjustment are quite complex. There are a number of issues concerning the Company’s methodology, such as the impact of reserve allocations on ramping, and whether ramping losses should be counted after a unit is returned from reserve shutdowns. Another concern is that the Company continues to count, as part of ramping losses, loadings less than full nameplate capacity for up to 12 hours after a unit is returned to service. This is well in excess of the time required to restart the Company’s units. As a result, I recommend further investigation of ramping in future cases.

VII. MODELING ISSUES DEFERRED FROM DOCKET 07-035-93

Q. DID THE COMMISSION DECIDE ALL GRID RELATED ISSUES IN THE 2007 CASE?

A. No. The Commission invited further analysis of two issues in subsequent cases: the minimum loading and heat rate deration adjustment, and the modeling of duct firing in GRID. Mr. Duvall addressed both of these issues in his testimony. However, I don't agree that the Company has satisfactorily resolved these issues.

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. 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)[15] percent of the time, and available at zero MW (because it is on an outage) EFOR[16] percent of the time.

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15 95% in the example above.
16 5% in the example above.

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's *minimum capacity,* MW(min) should also be derated in the same proportion 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 *derated maximum* capacity. While this may seem far fetched, it did occur in GRID simulations the Company filed in July, illustrating a serious problem in the Company's modeling.

Q. CAN YOU PROVIDE A SIMPLE EXAMPLE SHOWING WHY THIS ADJUSTMENT IS NECESSARY IN GRID?

A. Yes. Assume a hypothetical situation where a generator is dispatched at 10 MW for a 100 hour period. In this case, it would generate 1000 MWh. Now assume the unit was on forced outage half of that 100 hour period. In that case, it would only generate 500 MWh and have an outage rate of 50%.

If the unit has a maximum capacity of 10 MW, GRID's duration logic would treat it as a 5 MW unit running for all 100 hours. This is the way in which the derate model works. In that case, GRID would show it producing 500 MWh, and it would produce a result that matches with actual operation.

Now, however, assume that the unit really had a maximum capacity of 50 MW, but still had a minimum capacity of 10 MW and the same 50% outage rate. The same unit, dispatched at minimum for 100 hours, with a 50% outage rate would produce 500 MWh of energy. However, in this scenario, GRID would derate the maximum capacity to 25 MW - but it would still model a minimum capacity of 10 MW. This is because GRID would derate the maximum capacity for outages (50%) but would not do so for the minimum capacity. In this case, GRID would show the unit running at minimum capacity all 100 hours and still producing 1000 MWh, *or twice the correct amount*. Clearly, this problem must be fixed in GRID for results to be realistic.

Q. IS THIS THE ONLY ADJUSTMENT REQUIRED?

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

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

This is a non-linear equation that expresses the amount of heat consumed by the generating unit as a function of the capacity level that the unit operates at. A, B, and C reflect coefficients that were originally determined in a curve fitting procedure that was used to create the heat rate equation based on actual data obtained from performing tests on the generating unit. Here MWh is the loading of the unit in hour h.

If, for example, the unit is expected to be running at its maximum capacity, GRID's deration logic will multiply the unit's maximum capacity by its EFOR, as discussed above, and will treat it as a smaller unit running at less than full load. Returning to the original example of a 100 MW unit, GRID treats the 100 MW unit as a 95 MW unit for modeling purposes. Without a corresponding adjustment to the heat rate equation, the heat consumptions using the formula stated above will be incorrect, and will lead to an overstatement of the amount of heat consumed. The reason for this is that generating units are generally most efficient at their full loading point. Without an adjustment to the heat rate curve, GRID's deration logic will therefore overstate fuel costs.

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

Heat consumed = (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 consumed should be computed as (1-EFOR) times the heat input at full loading. GRID, however, would compute the heat input as shown below:

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

While there appears to be only minor differences in the two formulas in the case when a unit is fully loaded, the small differences can add up. Further, because unit efficiencies typically decline as unit loadings decrease (moving down the heat rate curve), ignoring this adjustment will increase NPC. Even worse, not making an adjustment to the heat rate curve could produce absurd results in some cases.

Q. WHAT ADJUSTMENT TO THE HEAT RATE CURVE DO YOU RECOMMEND?

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

Heat Rate Curve Adjusted = A x (1-EFOR)+B x MWh+ C/(1-EFOR) x MW_h^2

Fortunately, the Company already supplies an input to GRID which makes this very adjustment. All one really needs to do is to supply GRID with this input for each resource.

Q. HAVE THESE MODELING TECHNIQUES BEEN APPLIED ELSEWHERE?

A. Yes. In its MONET model, Portland General Electric ("PGE") applies the very type of technique I am proposing. Exhibits CCS 4.7a, 4.7b and 4.7c show data responses from a 2008 PGE case (OPUC Docket No. UE 197), confirming this fact. Further, In Docket No. 07-035-93, CCS witness Philip Hayet also testified that the method I am proposing is well accepted in the community of production cost modeling experts. Finally, I also testified that I applied the method in a production simulation model that enjoyed substantial industry acceptance more than 25 years ago.

Ironically, PacifiCorp itself actually applies both of these techniques (adjusting minimum capacity and heat rate) to fractionally owned units such as Colstrip. From a modeling perspective, fractional ownership is the same thing as capacity duration. There is no reason why the Company should apply the technique for fractionally owned units, while ignoring them for units that are modeled as a fraction of their total capacity. If one thinks of forced outages as a "co-owner" of the resource, that has a call on its output 5 or 10% of the time, it is easy to see why the modeling should in fact, be the same as for fractionally owned units.

Q. CAN YOU PROVIDE AN EXAMPLE ILLUSTRATING THIS PROBLEM?

A. Yes. In the Company's July GRID study, it modeled a monthly outage rate. For May 2009, the Company assumed an outage rate of 50% for Currant Creek. Applying that outage rate in GRID reduced the maximum capacity of the plant to around 210 MW. In the GRID modeling for May, 2008 the Company showed the unit running at 210 MW nearly all of the time. This is far less than the assumed minimum loading for the plant (340 MW), and resulted in an average heat rate for the unit of 9,184 BTU/kWh for the month. This result clearly is far in excess of what would normally occur for the plant in conventional operation (which typically averages 7,300 BTU/kWh.)

This problem stems from the unrealistic modeling of the unit with a large outage rate without making any corresponding adjustment to the minimum loading levels or the units heat rate curve. The Company would have exactly the same issue were it to model fractionally owned units without this adjustment. For this reason, the Company should make both the minimum loading and heat rate duration adjustments for all units which have non zero outage rates.

Q. HAVE YOU PREPARED AN ANALYSIS THAT TESTS THE REASONABLENESS OF THE COMPANY MODELING BASED ON ACTUAL DATA AND EVENTS?

A. Yes. I did several GRID simulations using the July filing, focusing on May 2009, which assumed a 50% outage rate for Currant Creek. This was used because

Currant Creek was off line most of May 2006, and on line nearly all of May 2007, the two years used by the Company to compute the Currant Creek outage rate.

To test the reasonableness of the standard GRID modeling I did one scenario using my proposed method, a scenario where Currant Creek was off line half the time in May 2009 (a logical way to represent a 50% outage rate) and scenarios with the plant on all month and off all month. The latter two scenarios can be averaged to result in a 50% availability case, again comparable to the Company's assumed outage rate.[17] If the GRID modeling is correct, the results from the standard method should be close to those obtained from the scenarios with Currant Creek out half the time, or based on the average of the fully on and fully off scenarios. However, the final results show GRID actually overstated the expected NPC (by $1.4-$1.7 million) and Currant Creek heat rates compared to the two logical alternative modeling methods and my proposed method. Further, the actual composite heat rate for Currant Creek for May 2006 and May 2007 was 7,310 BTU/kWh, which compares well with the result under all modeling methods (including mine) except the Company's standard approach. As noted above, the GRID model showed a heat rate for Currant Creek of 9,184 BTU/kWh. I think this demonstrates that the GRID logic is faulty, as its predicted results are the outlier. Exhibit CCS 4.8 shows the results of this analysis.

Q. THE COMPANY USED THE MONTHLY OUTAGE RATES BY MISTAKE IN ITS JULY FILING. HAS THE COMPANY SOLVED THIS PROBLEM BY ELIMINATING THE ERRONEOUS MONTHLY OUTAGE RATES IN ITS SUBSEQUENT FILINGS?

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[17] Note that there were very few durations during May 2006 and 2007, and duration events are uncommon for combined cycle plants in general.

A. No. The problem remains. It is simply *less obvious* because the extremely high May outage rate is now blended in with all the other months. This means that instead of May showing an obviously overstated heat rate in GRID, the heat rate for each individual month is overstated by a less noticeable amount.

Q. IN ITS ORDER IN DOCKET NO. 07-035-93 THE COMMISSION STATED IT WANTED TO EXAMINE THIS ISSUE FURTHER BEFORE ADOPTING IT. HAS THE COMPANY DISCUSSED THE ISSUE IN ITS TESTIMONY?

A. Yes. Mr. Duvall continues to argue that no adjustment is needed. Mr. Duvall has made a number of arguments concerning this issue. Mr. Duvall has made three basic points: 1.) Derating the minimum capacity would allow the model to simulate operation below its actual minimum, which he says the units can never achieve. Mr. Duvall warns this will produce unrealistic results; 2.) The adjustment I propose does not work properly because it ignores partial outages which result in units being derated but not completely out of service; 3.) Comparison of <u>actual</u> heat rates to GRID heat rates shows that no further adjustment is needed.

Q. HOW DO YOU RESPOND TO MR. DUVALL'S FIRST ARGUMENT?

A. First, the Company's modeling in GRID already allows a unit to run at a level below its minimum capacity rating, as was shown in the example of Currant Creek above. As long as the outage rate is high enough, GRID will allow units to run below its rated minimum capacity. Mr. Duvall does not seem to view this as a problem, and has proposed no correction for it.[18]

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[18] Correcting this problem would decrease NPC, as it would be equivalent to placing a limit on outage rates.

Second, Mr. Duvall objects to derating the minimum because it allows the model to let a unit run at a level it can never achieve. However, GRID already derates the maximum capacity even though that prevents the unit from *ever* running at a capacity it actually *can achieve*. If derating the minimum is unrealistic, then derating the maximum is as well.

Third, Mr. Duvall explicitly adopts the concept of "expected value" (which he calls a "hair cut") when GRID reduces the *maximum* capacity of resources below their physical limits, but would have the model ignore it for the equally valid issue of applying the minimum capacity. In CCS 29.16 and 29.17, I asked Mr. Duvall regarding the concept of expected value as applied to minimum and maximum capacities. Mr. Duvall did not provide an answer regarding maximum capacity ratings, simply returning to his argument concerning the physical limits for generator minimums. Ultimately, either the Company is correct in using the concept of expected value of capacity in GRID, or it isn't. If it is (and most experts believe it is), then unit minimum capacities should be derated just the same as the unit maximum capacity.

Q. DOES MR. DUVALL HAVE A POINT CONCERNING PARTIAL OUTAGES?

A. Yes. I agree that it is more proper to recognize that when partial outages occur, they are less likely to impact the minimum loading of a unit. As a result, I removed partial outages from my computations in performing this adjustment. This is different from the method I applied in Docket No. 07-035-93, and it serves to reduce the impact of this adjustment. I informed the Company last summer that I would be proposing this refinement.

Q. PLEASE DISCUSS MR. DUVALL'S ARGUMENT CONCERNING THE COMPARISONS TO ACTUAL HEAT RATES SHOWN IN EXHIBIT GND-4SS.

A. There are three important points. First, Mr. Duvall's figures shows the minimum loading and heat rate adjustment has very little impact on coal plants. In fact, the overall change to heat rates is far less than one half of one percent. At best, Mr. Duvall's limited data demonstrate that this issue is a "toss up" for coal units. However, noticeably *absent* from Mr. Duvall's heat rate comparison were the Company's gas units.[19] GRID consistently overpredicts the heat rates of gas units, and the minimum loading and heat rate adjustment really *enhances, rather than diminishes,* the overall accuracy of heat rates results simulated in GRID. Finally, my current method has been refined to more properly recognize partial outages.

The table below shows a comparison of the GRID simulation results and actual heat rates with and without this proposed adjustment. As the table shows, the Company's modeling method is not accurate when applied to gas units, which cycle more often. The Table shows that as concerns coal plants, there is really little basis for choosing between the two methods based on comparison to actual heat rates. However, when gas units are included, the method does produce more realistic results than the Company method. Overall, the use of the derate adjustments improves the system average heat rate results as compared to the current method modeled in GRID. I recommend the Commission adopt this adjustment and the impact is shown on item 21 on Table 1.

[19] Considering that Mr. Duvall himself has testified that the impact on coal plants is minor because they are us normally "in the money", it's puzzling that he would focus on coal plants for his analysis.

Table 3 – Comparison of Actual to GRID Heat Rates (BTU/kWh)

	Actual Data	Company Method	Derate Method
Coal Average	10,700	10,712	10,688
Coal Weighted	10,609	10,619	10,595
Gas Average	9,063	9,541	9,493
Gas Weigthed	7,387	7,509	7,461
Coal + Gas Avg.	9,882	10,126	10,091
Coal + Gas Wtd.	10,048	10,077	10,050

Q. ARE THERE ANY OTHER PROBLEMS WITH THE MODELING OF COMBINED CYCLE UNITS IN GRID THAT WERE DEFERRED IN DOCKET 07-035-93?

A. Yes. The Commission invited further investigation of this issue in subsequent dockets.

In GRID the Company models the duct firing capabilities of Currant Creek and Lake Side as generation resources that are independent of the underlying Combustion Turbines (“CT”) and Heat Recovery Steam Generators (“HRSG”). This has created problems where the duct firing capacity runs at times when the combustion turbines and steam generator are not running.[20] Mr. Duvall testifies that this problem has now been addressed because the plant as a whole uses the same screens.

A more serious problem is that GRID frequently shows duct firing operation of Currant Creek and Lake Side when the CTs and HRSGs of these units 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

[20] See the response to CCS 6.41, Docket No. 07-035-93.

combined operation of the CTs and HRSGs. 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 for 3975 hours per year for Currant Creek, or 74% of the time that duct firing is in operation. In fact, while Currant Creek CTs and HRSG are running at 340 MW (its assumed minimum loading) 4620 hours per year, the Duct firing is operating during 86% of those hours. This is a completely illogical simulation result. The GRID simulation results of Lake Side are much the same. Exhibit CCS 4.9 shows simulation results from GRID supporting these observations.

Q. CAN YOU PROVIDE AN EXPLANATION AS TO EXACTLY WHAT PROCESS GRID IS MODELING?

A. Yes. Duct firing is nothing more than injecting additional gas flames into the HRSG and obtaining more steam. Under the GRID modeling, it is assumed the Company would do this even though the CTs and HRSG are running at minimum loadings.

Q. ARE THERE OTHER MODELING PROBLEMS RELATED TO DUCT FIRING?

A. 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 the CTs and HRSG are 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. This is a major cause of the problem in modeling the duct firing and CT/HRSG capacity of

Currant Creek. GRID makes a mistake in the decision to start up the duct firing because it incorrectly assumes it is economical to do so, forcing reserves onto the CT/HRSG capacity. This is further manifestation of the GRID commitment logic error and the associated and undocumented “reserve credit” methodology.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING DUCT FIRING?

A. The Company should be required to develop a modeling enhancement for GRID that allows proper modeling of all modes of operation for combined cycle generators before the next general rate case is filed. In the meantime, the Commission should adopt an adjustment I am proposing in this case.

Q. EXPLAIN YOUR PROPOSAL.

A. I have used the GRID dispatch for Currant Creek and Lake Side to compute an adjustment outside of the model. As an example, consider hour 17 of January 1, 2009 (shown also on Exhibit CCS 4.9.) This hour shows the Currant Creek CT/HRSG resources running at minimum loading (340 MW), while the Currant Creek duct firing resource is running at 91 MW - fully loaded. This is a mode of operation that doesn’t make sense. However, the overall dispatch of the plant (in this case 431 MW) is feasible with the plant running in duct firing mode. This odd result occurs because GRID is allocating 87 MW of Currant Creek to reserves, and none to the Duct Firing resource. In effect, GRID assumes it makes sense to back down on the combustion turbines (thus forgoing some of the “free energy” available from the heat recovery steam generator) while cranking up the supplemental gas-firing. This is not an economical mode of operation, and one which the Company would normally not do.

Q. WHAT IS THE LOGICAL DISPATCH OF THESE RESOURCES?

A. In this scenario, it is reasonable to assume that because Duct Firing is needed, it should be dispatched at its minimum capacity (35 MW) with the residual amount available (91 minus 35, or 56 MW) allocated to reserves. In that case, the capacity of the Currant Creek plant dedicated to reserves would be the same, and the overall output of the plant would be the same. However, the operation would be more efficient. In this case, there would be an overall savings of XXX MMBTU, which is close to XXXXX savings based on $6/MMBTU gas.

Q. IS THIS HOW YOU COMPUTED THE ADJUSTMENT?

A. Yes. I performed this same analysis every hour for both Currant Creek and Lake Side. I took care to ensure that the duct firing was always dispatched at its minimum and that its reserve carrying capability was not exceeded. The results are shown as items 19 and 20 on Table 1.

VIII. TRANSMISSION MODELING

Q. HAS THE COMPANY CHANGED ITS TRANSMISSION MODELING IN GRID IN RESPONSE TO ISSUES RAISED BY THE COMMITTEE?

A. Yes. In Docket 07-035-93, the Committee recommended that the Commission require the Company to include non-firm transmission based on 48 months of history comparable to the modeling of market caps. This proposal was consistent with the transmission modeling required by the Commission for avoided cost modeling[21]. The Commission ordered the Company to make this adjustment in its next case.

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[21]/ Re PacifiCorp, Report and Order, Utah Public Service Commission Docket No. 03-035-14, at 14 (October 31, 2005).

The Company also changed its modeling of SP 15 adding a link to the PacifiCorp system. This adjustment appears to address some issues examined in discovery by the Committee.

Q. DISCUSS NON-FIRM TRANSMISSION MODELING.

A. I have reviewed the data used by the Company, and the workpapers supporting the GRID non-firm transmission links. I believe the Company has implemented the Commission's order in Docket 07-035-93. There are a few outstanding issues, however.

First, the Company has not included any non-firm transmission available to PacifiCorp's merchant function from PacifiCorp Transmission. ("Pac Tran"). Based on the Company discovery responses, (See CCS 30.2) the Company states:

> "Transactions identified in the Company's response to CCS Data Request 30.1; specifically Confidential Attachment CCS 30.1 -1, are all with PacifiCorp Transmission. These transactions are not included because they are not incremental to the transmission rights used in GRID. Rather, they are released firm network transmission rights that are repurchased by the merchant side of the business to facilitate making wholesale sales and to transfer undesignated network resources."

The Pac Tran non-firm transmission dwarfs the amount of non-firm transmission available from third party providers. It would be useful to have the Company rigorously demonstrate that all of the Pac Tran non-firm is already reflected in the FTR's modeled in GRID. While I am not proposing any adjustment related to this issue in the current case, this is an issue that warrants further analysis.

A second issue concerning non-firm transmission modeling is the fact that the volumes of third party non-firm transmission modeled in GRID are only about 12% of the actual volumes experienced during the four year period. As a result, it seems quite unlikely the modeling applied in GRID reflects the full value of non-firm transmission to the system. This also warrants further investigation.

Finally, the Commission order in Docket 07-035-93 required the Company to model non-firm transmission in a manner consistent with its modeling of market caps. However, the Company uses one year of data to establish the market caps, but uses four years of data to establish the non-firm transmission. Because most of the transmission assumptions used in GRID are based on a single recent year of data, I recommend that the same be done for non-firm transmission. This increases NPC by the amount shown on Table 1.

Q. DISCUSS THE ISSUE OF CAL ISO FEES AND SP 15 MODELING.

A. In the Company's prior filings (including those in July and September) the Company modeled transaction in SP 15, but no firm transmission links to the rest of the system. The Company's trading activities in SP15 require it to incur $11.2 million per year in wheeling expense from Cal ISO. These costs are included in test year revenue requirement modeled in GRID (See December MDR 2.81). A problem occurs because the SP 15 trading practices are tied to hedging strategies in the 4-Corners market. Absent any link between the system and SP 15, the GRID results for this strategy are unrealistic, unpredictable, and can be very costly in any given test year. These are issues that have been explored on discovery by the Committee and which I addressed in the recent Oregon case.

Q. HAS THE COMPANY ADDRESSED THE PROBLEM IN ITS DECEMBER FILING?

A. Somewhat. Mr. Duvall now includes a non-firm link between SP 15 and Four-Corners to allow the SP 15 trades to be settled at Four-Corners prices. This eliminates some ($5.4 million), but not all of the loss on SP 15 when the Cal ISO fees are included. On net, the Company would have $2.6 million in lower cost if the SP 15 transactions never take place, assuming all the Cal ISO fees were avoided. This, however, can't be proven since the Company doesn't differentiate Cal ISO fees in such a way as to quantify the amount related to SP 15.[22]

Q. WHAT IS YOUR RECOMMENDATION?

A. The Company has taken some steps to address this problem and I am not proposing an adjustment in this case. However, this is a very complex issue and certainly warrants further investigation.

SHORT TERM FIRM TRANSMISSION

Q. NOW THAT THE COMPANY IS INCLUDING NON-FIRM TRANSMISSION, DOES GRID CAPTURE ALL OF THE TRANSMISSION RESOURCES AVAILABLE TO THE COMPANY?

A. No, the Company ignores capacity available from short term firm transmission resources. However, the Company has included $13.0 million of cost related to some 29 short-term firm transmission contracts in the test year. See Confidential Exhibit CCS 4.10. Based on the response to CCS 23.16, only eight of these contracts, (costing $3.7 million) are used to make transfers internal to transmission areas or provide links between areas modeled in GRID. For the great majority of these contracts, all of the costs, but none of the capacity is modeled in GRID.

Q. CAN YOU PROVIDE AN EXAMPLE?

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[22] This was stated by Dr. Hui Shu, Manager of Net Power Costs at a February 9, 2009 meeting related to the 2009 Washington GRC.

A. Yes. The most significant example concerns short-term firm transactions with Nevada Power Company. GRID reflects $5.0 million in cost related to these transactions, but no capacity. According to data obtained in discovery, Nevada Power routinely provides PacifiCorp with over 100 MW of short-term firm transmission capacity from Mona to Palo Verde and 30 MW in the opposite direction. The response to CCS 30.3 shows hundreds of MW of short-term firm transmission capacity that has not been reflected in GRID, which the Company has used frequently in recent months and years.

Q. SHOULD THE COMMISSION INCLUDE STF TRANSMISSION CAPACITY IN GRID?

A. Yes. It is inconsistent to include some third-party short term firm transmission, but not all that is available. It is also inconsistent to include substantial costs related to STF transmission, but not include capacity associated with it. As the Commission decided in the case of non-firm transmission, the GRID model should recognize all of the resources available to the Company.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION?

A. I recommend the Commission implement a short term firm transmission adjustment to GRID based on use of 2007 average delivery rate for STF transmission contracts.

Q. WHY DO YOU RECOMMEND USE OF 2007 STF?

A. The Company bases all of its transmission cost on the most recent single year of data. The same should be done for STF transmission as well. The amount of the associated adjustment is shown as item 23 on Table 1. Because the GRID model flows resulting from these links is far less than those that actually occurred, I believe this adjustment is rather conservative. Further, the benefit of including STF transmission in GRID is still less than the costs modeled by the Company.

IX. OTHER ISSUES

Reserve Requirements for Non-Owned Generators

Q. PLEASE EXPLAIN THIS ISSUE.

A. There are many independent generators inside PacifiCorp's control area. The Company is required to provide reserves for some of these generators. In reviewing the Company's workpapers, I identified three errors in GRID. First, it appears the Company incorrectly copied the reserve requirement for non-owned generators from the workpapers to the GRID model. I believe the Company confirmed this error in December MDR 1.8. Second, the Company stated in CCS 31.4 that it included the reserve requirements for US Magnesium twice in GRID.

Finally, the Company has included costs related to providing reserves for West Valley even though the West Valley lease has terminated. There are a number of problems with the Company's approach. For example, the Company used historical data to estimate the loading of West Valley. However, the Company no longer owns the resource and based on GRID modeling, its primary purpose was to provide reserves. Absent that, West Valley would scarcely ever run based on current market prices.[23] As there is no way of knowing what the new owner's use of this resource will be (if any), there is no basis for including West Valley reserves in GRID. A further problem is that the revenue assumed by the Company available for providing reserves is less than the associated cost,

[23] This was confirmed using a GRID simulation.

forcing ratepayers to subsidize this activity. In addition, the revenues assumed by the Company, as shown in CCS 31.7, are more than the total ancillary services revenues provided the owner of West Valley, reported in CCS 23.49. These revenues appear the same as assumed by the Company in the 2007 case for the owner of West Valley, before the lease was terminated. Those revenues were related to the Stateline wind project. Thus, the Company has not provided adequate justification that the total revenues for ancillary services included in the test year really do reflect the West Valley contract. However, the Company may be able to demonstrate that the revenues from the West Valley sale were included in the test year, in their rebuttal testimony.

Items 27, 28 and 29 on Table 1 shows the impact of these corrections.

Cholla Maximum Capacity Rating

Q. HAS THE COMPANY CHANGED THE CAPACITY RATING USED FOR CHOLLA UNIT 4?

A. Yes. The Company reduced the nameplate capacity of Cholla from 390 to 387 MW. The Company did so because it only holds Firm Transmission Rights ("FTR") for 387 MW from Cholla to the rest of the system. There are at least two problems with this.

First, the Company is able to move some of the power from Cholla (1.2 MW on average) via short-term firm and non-firm transmission. The Company ignores this in making its reduction to the Cholla capacity.

Second, Cholla is plagued with a variety of problems that result in numerous capacity derations. In fact, the plant capacity is limited below 390 MW more than 80% of the time (more than 28,000 hours in the four year period).

These derations averaged 15 MW during the four year period. The Company already derates the capacity of Cholla for energy lost due to both full and partial outages. This deration places the available capacity of Cholla at a level far below the 387 MW transmission limit. Because the outage rate used in GRID already reflects the capacity derations due to all causes, further reducing the capacity of the unit to 387 MW would amount to double counting. I recommend the Commission reject this adjustment. The impact is shown as item 30 on Table 1.

Transmission Imbalance

Q. THE COMMISSION ADOPTED THIS ADJUSTMENT IN DOCKET 07-035-93. DID MR. DUVALL INCLUDE IT IN GRID?

A. No. Mr. Duvall argued in his September testimony that the Company does not benefit from imbalance premium or discount charges. This, however, is contradicted by the Company's response to a discovery request in Wyoming that indicated the Company charges amounts for this service that provide for a discount or premium to the market value of the imbalance energy. See, Exhibit CCS 4.11. The Company receives the benefit of a below market purchase when a customer has a positive imbalance (load exceeds schedule), and the benefit of an above market sale when the customer has a negative imbalance.

I conducted additional discovery on this issue in Oregon Docket UE 199. Mr. Duvall is correct that the Company doesn't benefit from imbalance charges for FERC OATT customers. Imbalance premiums or discounts are eventually redistributed back to customers who are not assessed penalties. However, for legacy transmission contract customers that is not the case and the Company retains the premium or discount. (See Exhibit CCS 4.11 for additional discovery responses.) It turns out that much of the premium or discount charges are associated with the legacy transmission contract customers. These include Deseret, UAMP, UMPA, and Warm Springs. As the Commission adopted this adjustment in the last case, and did not change its position on reconsideration, I include it in the GRID model.

Q. DOES THE COMPANY MODEL ANY TRANSMISSION RELATED IMBALANCE COSTS IN THE TEST YEAR?

A. Yes. First, the Company includes a provision for additional transmission charges when generation imbalances exist in GRID.[24] Such costs were included by the Company in many GRID studies, including the July and September filings in this case, and both of the Company's GRID studies filed in its rebuttal case in Docket No. 07-035-93. Further, the Company also includes charges for ancillary services in the Transmission Wheeling cost entry in GRID. It seems quite likely that transmission imbalance charges would be included as part of ancillary services. I have reviewed the workpapers used by the Company and see no evidence that transmission imbalance charges have been removed from these entries. Finally, the Company includes "Miscellaneous Transmission Expenses" in the test year, which may also include imbalance payments. If the Commission decides to reverse itself on this issue, it should also direct the Company to remove any payments it made for imbalance costs in the test year. Conversely, if the Company did not include any such payments, I recommend they be included, offsetting this adjustment.

Q. HOW DID YOU COMPUTE THIS ADJUSTMENT?

[24] See WIEC 4.34c, Wyoming Public Service Commission Docket No. 20000-277-ER-07 included with Exhibit CCS 4.11

A. Transmission imbalance is priced at a premium or discount to the market price. Since the Company has to acquire or dispose of the imbalance energy at market, the ultimate effect is financial. The Company benefits whether there is a positive or negative imbalance. As a result, I modeled this adjustment as a purely financial adjustment. This adjustment is shown on Table 1 as item 31.

<u>Comparison to the 2009 Budget</u>

Q. DO YOU HAVE ANY INFORMATION TO HELP ESTABLISH THE OVERALL REASONABLENESS OF YOUR RECOMMENDED 2009 NPC?

A. Yes. In CCS data request (“DR”) 29.12 I requested the Company’s NPC budget for 2009. Begin Confidential ………………………………………………………………………………………… ………………………………………………………………………………………. …..End Confidential Certainly, there are reasons why normalized power costs may differ from budget. For example, the Company likely budgets for the SMUD contract at its actual contract price, while it includes it in the test year at the imputed price. Further, budgets sometimes embody corporate goals to spur performance, such as improvements in plant reliability, increased efficiency, etc. However, the budget should represent a reasonable, achievable forecast for the Company, as it is one of the most critical decision making tools of any business. As a result, I believe the budget figures illustrate my results are reasonable.

PART II. ROLLING HILLS PRUDENCE AND WIND RESOURCE ISSUES

Q. PLEASE DESCRIBE THE ROLLING HILLS PROJECT.

A. This project is 25 miles east of Casper, Wyoming. The project has 66 General Electric Company ("GE") 1.5 MW wind turbines, for a total installed capacity of 99 MW. (The size of the project is important for reasons I will discuss later.) The project is located on land owned by the Company that was reclaimed from Dave Johnston plant mining operations. The project is adjacent to the Glenrock wind farm site, but is upwind and at a lower elevation.

Q. HAS THE ROLLING HILLS PROJECT ALREADY BEEN THE SUBJECT OF A PRUDENCE REVIEW BY ANOTHER STATE REGULATORY COMMISSION?

A. Yes. In Oregon Public Utility Commission ("OPUC") Docket No. UE 200 (the 2008 Renewable Adjustment Clause, or "RAC" proceeding) the OPUC considered the prudence of the Rolling Hills project.[25] As mentioned in my summary, the OPUC implemented a substantial disallowance for Rolling Hills in that case.

Q. PLEASE PROVIDE A BRIEF HISTORY OF THE DEVELOPMENT OF ROLLING HILLS.

A. PacifiCorp had originally ordered wind turbines for a different site in another state. Confidential CCS Exhibit 4.12 is a copy of documents relied upon by executives at PacifiCorp to support the decision to construct Rolling Hills.[26] The

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25 I obtained numerous confidential documents in that proceeding and in the current Wyoming general rate case as well as in the discovery in this case. I also requested many of the same documents in this case. Also, by virtue of agreement by the Company all of these documents from any of these states are available for use in this proceeding, subject to the respecting their confidentiality. As a result, in a few situations I may refer to documents produced in other states.

26 Source: Attachment CCS 5.6b Confidential.

document states that the original site (Confidential………..) was rejected in favor of the Rolling Hills site because Begin Confidential ……………………………………………………………………………………….. End Confidential .” Confidential CCS Exhibit 4.12 at page 10. Instead, the Company chose to develop the Rolling Hills site based on an assumed capacity factor of 31%. Id. As a result, the Company decided to use the turbines it had available at Rolling Hills rather than the original site.

Q. IS THE EXPECTED CAPACITY FACTOR OF A WIND RESOURCE A SIGNFICANT DRIVER OF PROJECT ECONOMICS?

A. There is no question about that. Because wind resources have zero variable costs, the cost per kWh of output is simply the fixed cost divided by the project output. The greater the output of the wind farm, the lower the cost per kWh. Therefore, the expected annual generation, or capacity factor, is critical to the ultimate economics of any wind project. Considering that a XXX reduction in the assumed capacity factor was sufficient for the Company to abandon the XXXXX XX project, it should be clear that the capacity factor assumption was crucial to the economics of Rolling Hills.

Q. CAN YOU PROVIDE A NUMERICAL EXAMPLE SHOWING THE SIGNIFICANCE OF CAPACITY FACTOR TO THE ECONOMICS OF A WIND PROJECT?

A. Yes. Based on data provided by the Company, the Seven Mile Hill wind project had an expected capacity factor of 41%, while Rolling Hills was only 31%. Because the two projects have approximately the same revenue requirement, for the test year, Rolling Hills costs $87/MWh, while Seven Mile Hill costs only $68/MWh.

Q. DESCRIBE THE INFORMATION USED BY THE COMPANY TO ESTIMATE THE EXPECTED CAPACITY FACTOR FOR ROLLING HILLS.

A. Review of the available documents indicates that before the decision was made to construct Rolling Hills the Company was warned by Begin Confidential ………………………………………………………………………………………… ……………………………………………………… End Confidential

Q. PLEASE ELABORATE.

A. Confidential CCS Exhibit 4.13 is a copy of a Begin Confidential ………………………………………………………………………………………… ………………………………………………………………………………………… ………………………………………………………………………………………… ………………………………………………………………………………………… ……………………………………… End Confidential

Q. PLEASE DESCRIBE THE METHODOLOGY USED IN THIS ANALYSIS.

A. Begin Confidential ………………………………………………………………………………………… ………………………………………………………………………………………… ………………………………………………………………………………………… ………………………………………………………………………………………… ………………………………………………………………………………………… ………………………………………………………………………………………… …………………………………………………………………………………………

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Q. WAS THIS EFFORT DEEMED A SUCCESS?

A. Begin Confidential ……………………………………………………………………End Confidential

Q. PLEASE RELATE SOME OF THE CONCLUSIONS OF THE STUDY.

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End Confidential.

Q. WHAT WAS THE PROJECTED CAPACITY FACTOR FOR GLENROCK AT THAT TIME?

A. Confidential Exhibit CCS 4.14 (Attachment CCS 5.6a Confidential) provides a copy of a May 2007 analysis provided to Company executives to evaluate the decision to construct Glenrock. The Glenrock economic analysis assumed a Confidential. (See Confidential CCS Exhibit 4.14 at page 12).

Begin Confidential

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………. End Confidential.

Q. DOES CONFIDENTIAL CCS EXHIBIT 4.14 ALSO REVEAL ANY ADDITIONAL PROBLEMS RELATED TO THE ROLLING HILLS PROJECT?

A. Yes. Begin Confidential

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…... End Confidential. (Id.) However, in response to discovery requests asking for an analysis quantifying this assumed degradation the Company stated, "The requested study has not been completed."[27]

Q. IS THERE ANOTHER REASON WHY THE ISSUE OF THE DEGRADATION OF GLENROCK IS SIGNIFICANT FOR ROLLING HILLS?

A. Yes. The degradation of Glenrock should have been seen by the Company as the equivalent of a lower capacity factor for Rolling Hills. For example, rather than having a project with an average capacity factor of 35% (31% for Rolling Hills and 39% for Glenrock), the overall project capacity factor would be 34.5% (31% for Rolling Hills and 38% for Glenrock.) As a result, *the opportunity cost* of the Rolling Hills project included the degradation of Glenrock. A realistic economic analysis of Rolling Hills should have penalized Rolling Hills for that problem by use of a *lower* (than 31%) capacity factor. Instead, the Company stated that it reduced the capacity factor for Glenrock in its economic evaluations, thus impairing the superior project. See again Confidential CCS Exhibit 4.14 at page 12. Begin Confidential

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……………. End Confidential. This hints there was already substantial sentiment within the Company in favor of Rolling Hills, even before any detailed studies were completed.

Q. RETURNING TO CONFIDENTIAL CCS EXHIBIT 4.13, ARE THERE ANY OTHER SIGNIFICANT STATEMENTS?

27 ICNU 15.21 OPUC Docket No. UE 200

A. Yes. Based on the document, the Company also Begin Confidential ……………………………………………………………………….. End Confidential:

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……………………………End Confidential.

The last statement, regarding the need for “Confidential……………………………” is clearly quite significant as well.

Q. **WERE THERE ANY PROBLEMS WITH THE WIND POWER DATA AVAILABLE TO THE COMPANY?**

A. Yes. Confidential CCS Exhibit 4.15 is a copy of an analysis completed in April 2007 that examined the wind potential for the Glenrock and Rolling Hills sites.[28] This report was apparently the basis for the document attached as Confidential CCS Exhibit 4.14 which was used by the Company to support the "go ahead" decision for Glenrock.[29] The significance of this document is that it demonstrates the assumed production of Rolling Hills (Confidential …………………………….) may have been too optimistic. Begin Confidential………………………………………..

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[28] Source: OPUC Docket No. UE 200. The document was provided to me by counsel for PacifiCorp at the UE 200 hearing who stated it had been overlooked in the discovery process.

[29] Confidential……………………………………………………………………………
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Q. SUMMARIZE WHERE THINGS STOOD WITH RESPECT TO ROLLING HILLS AS OF SEPTEMBER 2007.

A. As of that time, the Company had already committed to construct Glenrock as a 99 MW wind project, Begin Confidential ………………………………………………………………………………………… ………………………………………………………………………………………… ………………………………………………………………………………………… ………………………………………………………………………………………… ………………………………………………………………………………………… ………………………………………………………………………………………… ………………………………………………………………………………………… ……………………. End Confidential.

Q. COMPARE THE QUALITY OF WIND DATA AVAILABLE FOR ROLLING HILLS TO THAT OF CONFIDENTIAL.

A. Begin Confidential ………………………………………………………………………………………… ………………………………………………………………………………………… ………………………………………………………………………………………… ………………………………………………………………………………………… ………………………………………………………………………………………… ………………………………………………………………………………………… ………………………………………………………………………………………… ………. End Confidential.

Q. WHAT HAPPENED AFTER SEPTEMBER, 2007?

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End Confidential

Q. **WHAT HAPPENED NEXT?**

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Q. WHAT IS YOUR INTERPRETATION OF THESE EMAILS?

A. Begin Confidential

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Q. WHAT WAS THE RESULT OF THIS ANALYSIS?

A. Confidential CCS Exhibit 4.17 Begin Confidential………………………………………….. End Confidential. The report states that: Begin Confidential ……………………………………………… End Confidential" Confidential CCS Exhibit 4.17, page 1.

Q. HOW DOES THE WIND DATA THE COMPANY HAD FOR ROLLING HILLS COMPARE TO THAT WHICH IT HAD AVAILABLE FOR OTHER SITES?

A. The Company used far less reliable wind information in the development of the Rolling Hills project than it did for the Company's other projects. The process used normally involved construction of several test towers with wind measuring

[30] xxxxxx

equipment, and collection of several years' worth of data. This was the process used in other wind projects developed by the Company or third party developers. In discovery, the Company provided a number of studies prepared to evaluate the wind energy potential of other sites it was involved with. In some cases, multiple consultants' studies were provided and, in most cases, there were multiple wind metering towers measured. The table below provides an analysis of the number of towers used for the various projects, and the number of years of data collected for each sites. As the confidential table below shows, the data used for Rolling Hills was far less detailed and appears inadequate compared to other sites.

	x	**Confidential**		
x	**x**	**x**	**x**	**x**
x		x x	x)	
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x		x x	x)	
x		x x	x)	
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It should be pointed out that not all of the towers were used in all of the projections of wind potential. However, the presence of multiple towers at a site allowed for exclusion of towers that produced questionable data, or were only available for a limited period of time.

Q. EXPLAIN THE SIGNIFICANCE OF THE COMPARISON TOWER.

A. The use of a comparison tower is important, because long term studies required more data than a short sample period (5 years or less) might provide. The process normally followed was to correlate wind data obtained for a shorter period at a site, with data from an observation point with a longer history of data being available. This was done to provide evaluations of wind potential spanning many years of data. Begin Confidential ……………………………………………………………………………………… ……………………………………………………………………………………… ……………………………………………………………………………………… ……………………………………………………………………End Confidential. (Confidential CCS Exhibit 4.17, page 7).

Q. WHAT WIND DATA WAS USED TO DEVELOP THE ROLLING HILLS ESTIMATES?

A. Begin Confidential ……………………………………………………………………………………… ……………………………………………………………………………………… ……………………………………………………………………………………… ……………………………………………………………………………………… ……………………………………………………………………………………… ……………………………………………………………………………………… ………………………………………………………………………………………… ……………………………………..……… End Confidential.

Confidential CCS Exhibit 4.17, pages 6-7.

Q. WHAT WERE SOME OF THE KEY FINDINGS IN THE ROLLING HILLS WIND POTENTIAL REPORT?

A. The report makes the following statements:

1. *Begin Confidential………………………………………………………*

2. ………...

3. ……….

4. ……………………………………………………………………………………………………...

…….*End Confidential.*

Confidential CCS Exhibit 4.17, page 7.

Q. PLEASE EXPLAIN STATEMENT 1 ABOVE.

A. Begin Confidential………End Confidential. This was a somewhat more tactful way of saying what the Company had already been told: *Confidential………………………………………………*.

Q. PLEASE EXPLAIN STATEMENT 2 ABOVE.

A. Begin Confidential ………

………………………………………………………………….. ..End Confidential."

Confidential CCS Exhibit 4.17, page 7.

Q. EXPLAIN THE SIGNIFICANCE OF TOWER HEIGHTS MENTIONED IN STATEMENTS 3 AND 4.

A. Begin Confidential …… End Confidential.)

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE DEVELOPMENT OF THE ROLLING HILLS SITE?

A. With respect to the prudence of the project, there are a number of "red flags," particularly concerning the wind data used to evaluate the economics of the resource. The consultants' report relied upon by the Company was nothing more than a "Begin Confidential……………………………………… End Confidential. The report specifically called for

Confidential……………………….... Despite all of this, the Company told its board and executives that "Confidential……………………………………………….....” Confidential CCS Exhibit 4.12, page 1. Confidential…………………………………………………………………………. …………………………………..

Q. PLEASE RELATE THIS TO THE PRUDENCE STANDARD.

A. Prudence is normally defined in terms of the "reasonable person standard." This holds that actions would be considered to be prudent if they are consistent with those of a reasonable person who possessed the qualifications and experience necessary to make the decision and who acted with a standard of care consistent with the importance of the problem at the time. The Company's decision to pursue the Rolling Hills project was not prudent based on this standard.

Q. PLEASE EXPLAIN.

A. The Rolling Hills project represented an investment with an assumed life of 25 years costing more than $200 million. The staggering sum of this investment (nearly two thirds the cost of the Currant Creek and Lake Side projects) meant it was a very important decision. A reasonable person would not decide to spend $200 million on a study supported by "Confidential……………" derived from use of "Confidential……." practices, particularly when the person's expert advisor recommended Confidential…………… in order to adequately characterize the site. My interpretation of the Begin Confidential…………………………………………………………………………

……………………………………………………………………………………End Confidential. As such, the Rolling Hills project fails under the prudence standard based on the evidence currently available at that time.

Q. HOW SHOULD THE COMMISSION ADDRESS THIS ISSUE?

A. If the Company were to guarantee a reasonable capacity factor for this project, it would moot this discussion. However, in OPUC Docket No. UE 200, the OPUC Staff recommended use of a permanent 38% capacity factor, and the Company opposed that recommendation. The OPUC didn't adopt that recommendation either. Further, in Docket No. 07-035-93 the Company opposed a proposal to guarantee wind project capacity factors, and the Commission agreed with the Company. The Committee would consider a guaranteed capacity factor proposal, however. The 38% figure proposed by the OPUC is reasonable, compared to the currently forecast figures for Seven Mile Hill and Glenrock, for example.

Absent that, I recommend that the Commission deny recovery of Rolling Hills costs. However, I believe it would be worthwhile for the Company to reconsider use of a guaranteed capacity factor.

Q. WHAT DISALLOWANCE DO YOU RECOMMEND?

A. Based on data contained in CCS 5.9, I computed the Rolling Hills requirement for the test year. Removing the project from rate base should be accompanied by its concurrent removal from GRID increasing NPC. These impacts are shown on Table 1.

This disallowance, even if invoked for the life of the resources, would not necessarily have an undue adverse impact on the Company over the long term.

While this project is imprudent as a regulated generation asset, Begin Confidential………. End Confidential. See Confidential Exhibit CCS 4.12, page 4.

Q. PLEASE EXPLAIN HOW ROLLING HILLS CAN BE IMPRUDENT, BUT AT THE SAME TIME MAY CONFIDENTIAL……………………………..

A. Prudence deals with the decision making process and whether it was reasonable and well informed. In this case the decision was most certainly not well informed. The question of whether the project Confidential……………………….. A bad decision can result in a good outcome, just as a good decision can result in a bad outcome. Confidential……………………………………………………………………………………………….." By disallowing recovery on Rolling Hills the Commission would be placing the *risk* of the Company's imprudence right where it belongs - on the investors, not the ratepayers.

Q. DO YOU HAVE ANY COMMENTS CONCERNING WHY THE COMPANY MAY HAVE DECIDED TO CONSTRUCT ROLLING HILLS, IN THE ABSENCE OF CONFIDENTIAL?

A. Please refer again to Confidential CCS Exhibit 4.12. On page 11, under the heading of Regulatory Risk it is stated "Begin Confidential ………

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End Confidential.

Q. WHAT IS THE CAPACITY FACTOR FOR ROLLING HILLS THAT IS BEING USED IN THE 2009 GRID STUDY?

A. GRID shows a capacity factor of 33.7% for the test year ended December 31, 2009. This is above the 31% net capacity factor discussed in the documents discussed above because the Company produced a new study of the Rolling Hills capacity factor in the late stages of UE 200 in Oregon. Confidential……………………………………………………………….. This study was completed in August of 2008.However, prudence concerns what was known at the time a decision was made, not what may have been learned sometime after the fact. Second, the new capacity factor study is itself based on highly questionable wind data. The document reveals that it is premised on less than six months of wind data collected from December 2007 through May 2008. Further, the report indicates that the turbine designations were changed limiting the usefulness of comparisons to earlier studies.

Q. HAS ANY OTHER REGULATORY COMMISSION RENDERED A DECISION REGARDING ROLLING HILLS PRUDENCE?

A. Yes. In UM 200, the 2008 RAC case in Oregon, the OPUC denied recovery of the costs associated with the Rolling Hills project on the basis of prudence:

"Pacific Power's Rolling Hills project's specifications are markedly inferior, compared to either Glenrock or Seven Mile Hill, or other Wyoming wind projects in general. Without the objective evidence that would otherwise be provided by the competitive bidding process, Pacific Power must establish that it was prudent for the Company to develop the project at this time and at this location.

In their testimony and briefs, the parties cite evidence regarding the estimated capacity factors for each of these three resources at the time of project approval and at subsequent intervals. According to Pacific Power, the estimated capacity factor at the time of project approval was 41.3 percent for Seven Mile Hill, 38.6 percent for Glenrock, and 31 percent for Rolling Hills. The estimated capacity factor at the time of project approval is the crucial factor in deciding whether the project was prudently acquired.

To overcome the weight of the evidence about the relatively poor capacity factor for Rolling Hills, Pacific Power argues that external considerations were crucial factors contributing to its decision to proceed with the project. One of these factors was the availability of the wind turbines.

Pacific Power states that its choice was not between Rolling Hills and another project, but between Rolling Hills and no project, because the Company would not have been able to hold the turbines made available to it for the duration of the RFP process. That rationale is inconsistent with other statements by the Company explaining its decision to proceed with Rolling Hills.

Pacific Power originally planned to develop another site in Idaho and acquired the turbines for that site. The Company has failed to prove that it could not have stored the turbines or that it could not have negotiated with the manufacturer to resell them if it had no immediate use for them.

Pacific Power disputes the availability of other sites at the time it decided to proceed with Rolling Hills. However, Staff rightly argued that the Company conducted no discovery for alternate sites. The public record (such as siting approval applications filed in Wyoming) does not provide an exhaustive inventory of sites that may be available, both within and outside the Company's service territory. Again, the failure to solicit competitive bids is a factor that undermines the weight of the Company's evidence.

Pacific Power cites the possible expiration of the federal production tax credits as a factor in its decision to proceed with Rolling Hills. Without regard to the probability that the tax credits would expire, the Company failed to prove that the availability of the credits was a material factor in its decision to proceed with the project.

Further, the Company did not make a strong case that it needed to act to meet Renewable Portfolio Standard targets or other commitments. Nor are we persuaded by evidence comparing the Rolling Hills project to other projects in other regions. Pacific Power's burden was to prove that it prudently acquired the Rolling Hills project. The relevant alternatives are other wind projects in

> Wyoming that might have been – or may be – available." (OPUC Docket UE 200, Order 08-548, pages 19-20.)
>
> * * *
>
> "As noted above, SB 838 provides for the recovery of prudently incurred costs attributable to eligible projects through the RAC procedure. Because we find that Pacific Power failed to prove that it prudently acquired the Rolling Hills project, all costs associated with that project are excluded from the RAC cost recovery mechanism." (Id, page 20.)

Finally, it should be noted that Rolling Hills was ostensibly part of PacifiCorp's compliance plan with the Oregon Renewable Portfolio Standard (referred to as SB 838 in the OPUC order). Given the political popularity of renewable energy in the northwest, I believe it is safe to say the OPUC viewed the Rolling Hills project as a serious issue and most certainly did not make their decision lightly. Indeed, two of the Commissioners actually wrote supplements to the decision further explaining their views on the matter.

GLENROCK CAPACITY FACTOR

Q. ARE THERE ANY OTHER ASPECTS OF THIS PROBLEM THAT SHOULD BE ADDRESSED?

A. Yes. As discussed in the documentation, Rolling Hills is expected to have a detrimental impact on the capacity factor of Glenrock. Because Rolling Hills should not have been developed, the degradation of the Glenrock capacity factor should be reversed as well. Further, the Company changed turbine designations in its latest Glenrock capacity factor study. As a result, I recommend the Commission direct the Company to not only remove Rolling Hills from the GRID study, but to also make an upwards adjustment to the Glenrock capacity factor, as well. This impact is shown on Table 1.

This remedy was also adopted by the OPUC in UE 200:

"For Glenrock, the current estimated capacity factor is 37.4 percent, down from the estimated capacity factor at project approval of 38.6 percent and the capacity factor of 41 percent reported in an interim study, as proposed by Staff. For purposes of this proceeding, we set the capacity factor at 37.4 percent, as proposed by Pacific Power, and adjust it upward to make the discrete adjustment proposed by Staff to account for the degradation of Glenrock's performance caused by the development of Rolling Hills. Pacific Power is directed to make this discrete adjustment in the TAM updates. " (id, page 21, internal footnotes omitted.)

<u>POLICY ISSUES CONCERNING THE 99 MW WIND PROJECTS</u>

Q. ARE THERE ADDITIONAL POLICY ISSUES REGARDING ROLLING HILLS AND THE COMPANY'S OTHER WIND PROJECTS?

A. Yes. The Company has included two more 99 MW wind projects in the test year and two smaller projects as well. The sizing of these projects raises important policy concerns which have a bearing on the Rolling Hills prudence issue.

Q. WHAT OTHER 99 MW OR SMALLER WIND PROJECTS ARE INCLUDED IN THE TEST YEAR?

A. There are two other 99 MW projects in the test year: Glenrock and Seven Mile Hill. As stated previously, the Rolling Hills project is also sized at 99 MW. Further, the Company is adding additional turbines to these sites (Glenrock III (39 MW) and Seven Mile Hill II (19 MW) which will bring the total for each project well above the 99 MW thresholds (237 MW for Glenrock/Rolling Hills and 118 MW for Seven Mile Hill).

Q. WHAT IS THE SIGNIFICANCE OF THE 99 MW SIZE FOR THESE PROJECTS?

A. At the time the Company decided to build these projects, Utah rules required competitive bidding for projects 100 MW or larger. Current rules in Oregon also require competitive bidding for projects 100 MW or larger. As a result, by sizing these projects smaller than 100 MW, the competitive bidding requirements in both states were avoided by the Company. I am informed by the Committee that in May 2008 Utah increased the competitive bidding threshold for renewable projects to 300 MW and also established a process to better evaluate the cost of renewable projects.

Q. COULD THESE PROJECTS HAVE BEEN SIZED LARGER THAN 99 MW?

A. Yes. Wind projects are made up of many small (typically around 1.5 MW) wind turbines. Presuming a large enough site, by adding a specific number of turbines at the site, one could always develop a project 99 MW or larger. As can be seen from Exhibit CCS 4.19 (a map of the two projects), Glenrock and Rolling Hills are at adjacent sites which run parallel to each other. The delineation between Glenrock and Rolling Hills appears somewhat arbitrary from this map. In fact, as discussed above, the Company actually changed the designation of some of the turbines at the site. See CCS Exhibit 4.20 (the response to CCS 16.63). Turbines originally designated as Glenrock and Glenrock III, for example, were later designated as part of Rolling Hills. Likewise, turbines previously designated as part of Rolling Hills were later designated as part of Glenrock and Glenrock III. Thus, it might be viewed as one project not two or three projects. Further, Glenrock III Begin Confidential……………………………………………End Confidential.................................... See Confidential Attachment CCS 5.6c, page 7 and CCS 16.64. Seven Mile Hill 2 Confidential…………………………………………………………………………. See Confidential Attachment CCS 5.6e, page 7.

In the end, there is really no reason why Glenrock and Rolling Hills could not have been a single project of more than 200 MW. Likewise, there is no reason why Seven Mile Hill could not have been developed as a single project larger than 100 MW. The size of these projects is really little more than a result of use of multiple CCN applications to circumvent the competitive bidding rules.

Q. WHY DID THE COMPANY SAY IT DECIDED TO BUILD MULTIPLE WIND PROJECT RATHER THAN LARGER PROJECTS?

A. I first asked about this in the 2007 Wyoming rate case. Exhibit CCS 4.20 contains a copy of the answers to WIEC DRs 18.3 and 18.4 from Wyoming Docket No. 20000-277-ER-07. In WIEC DR 18.4, the Company suggested that if it was required to undergo a competitive bidding process as required under Utah regulation for projects over 100 MW, it could not have expected to complete the projects in time to obtain the Federal Production Tax Credit ("PTC"). These were then scheduled to expire at the end of 2008.

Q. MIGHT THE PRODUCTION TAX CREDIT ARGUMENT ALSO HAVE A BEARING ON THE QUESTION OF THE WIND ENERGY POTENTIAL OF ROLLING HILLS?

A. Perhaps. Confidential……………………………………………………………………. Xxxxxxxxx xxxxxxxxxxxx as recommended by their outside experts, because doing so would have delayed completion of the project beyond the end of 2008. The same argument could

Confidential……………………………………………………………………… ……..

Q. DO YOU HAVE ANY DOUBTS ABOUT THESE EXPLANATIONS?

A. Yes. I requested materials presented to the Company executives and/or Board regarding the recommendations to proceed with these projects. Various confidential documents were provided. See again Confidential Exhibit CCS 4.12. Begin Confidential …………………………………………………………………………………… ……………………………………………………………………End Confidential .[31] x . Given that these projects were supposed to come on line in December 2008, this seems to be a critical timing issue. Had these projects been delayed for unforeseen reasons the PTC may not have been available if the credits were not extended. This would certainly raise doubt regarding the overall viability of the projects since a December 31, 2008 completion date left no margin for error. Indeed, it's a fact that Rolling Hills and Glenrock III were not completed until January 17, 2009. Ultimately, the PTC's were extended as part of the recent $700 Billion Troubled Asset Recovery Program ("TARP") legislation, largely mooting these issues. While arguably the Company did not know at the time whether the PTCs would be extended, or whether the projects would all be completed on time, if the Company did undertake these projects in order to obtain the PTCs it was a rather large gamble on their ability to finish the projects before the end of 2008.

[31] The documents did present some financial results with and without the PTCs, but there was no other discussion of the issue.

Also, that the US House had already passed a bill extending the PTCs (H.R. 2776) before the Company decided to proceed with Rolling Hills in late 2007.

Q. WHAT IS YOUR CONCLUSION REGARDING THE PTC ISSUE?

A. This justification seems unsupported by the facts.

Q. IS THERE A POLICY ISSUE AT STAKE HERE FOR THE COMMISSION?

A. Yes. The Company's motivation in sizing these projects was questionable, if not imprudent and suggests the Company was actively working to circumvent the competitive bidding process. This has troubling implications for future RFPs. Consideration of this issue lends further support to the Committee's Rolling Hills rate treatment proposal.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.