**Witness OCS 4D**

**BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH**

| | | |
|---|---|---|
| **In the Matter of the Application of** | **)** | **Docket No. 13-035-184** |
| **Rocky Mountain Power for Authority to** | **)** | |
| **Increase its Retail Electric Service Rates in** | **)** | **Direct Testimony of** |
| **Utah and for Approval of its Proposed** | **)** | **Philip Hayet** |
| **Electric Service Schedules and Electric** | **)** | **On Behalf of the** |
| **Service Regulations** | **)** | **Utah Office of** |
| | **)** | **Consumer Services** |

**REDACTED**

**May 1, 2014**

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. Philip Hayet, 215 Huntcliff Terrace, Sandy Springs, 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 Hayet Power Systems Consulting ("HPSC"). I am appearing on behalf of the Office of Consumer Services ("OCS").

**Q. WHAT CONSULTING SERVICES ARE PROVIDED BY HPSC?**

A. HPSC provides consulting services related to electric utility system planning, energy cost recovery issues, revenue requirements, regulatory policy, and other regulatory matters.

**Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND APPEARANCES.**

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

## I. <u>INTRODUCTION AND SUMMARY</u>

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. My testimony addresses PacifiCorp's Generation and Regulation Initiatives Decision ("GRID") model study of Net Power Costs ("NPC") for the projected test period ending June 30, 2015. I also address issues related to the Company's approach to updating the Net Power Cost study during rate cases.

**Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

A. I have identified and quantified 10 adjustments to the Company's Test Year NPC GRID study. These adjustments are shown on Table 1 and are summarized below.

**Table 1**
**Summary of Recommended Net Power Cost Adjustments ($)**

| | Total Company | Utah Allocation |
|---|---|---|
| | | SE 41.97% |
| | | SG 42.63% |
| **Company Inital GRID NPC Request** | 1,521,859,578 | 643,746,905 |
| **Company April Updated NPC** | 1,510,208,987 | 638,818,702 |
| **A. Company Update** | | |
| **1 Company Update (April 2014)** | (11,650,591) | (4,928,202) |
| **B. Thermal Unit Modeling** | | |
| *Extended Outages* | | |
| **2 Colstrip 4** | (1,099,664) | (465,158) |
| **3 Lakeside 1** | (2,325,931) | (983,869) |
| **4 Gadsby 4** | (146,716) | (62,061) |
| *Heat Rate and Fuel Cost* | | |
| **5 Heat Rate/FOR Adjustment** | (7,229,553) | (3,058,102) |
| *Start Logic and Costs* | | |
| **6 Gas Start Up Costs** | (2,003,492) | (847,478) |
| **C. Contracts** | | |
| **7 Black Hills Power** | (625,434) | (264,559) |
| **D. Transmission** | | |
| **8 Loss Adjustment** | (1,685,806) | (713,096) |
| **E. Market Caps** | | |
| **9 Remove Market Caps** | (16,136,604) | (6,825,787) |
| **F. Balancing/Overlap Adjustment** | | |
| **10 Estimated Adjustment** | 1,003,881 | 424,642 |
| | **Total Company** | **Utah Allocation** |
| **Total Recommended Adjustments:** | ($30,249,318) | ($12,795,468) |
| **Final OCS Net Power Costs:** | $1,479,959,668 | $626,023,235 |

**Q. HOW DID YOU COMPUTE YOUR PROPOSED ADJUSTMENTS?**

**REDACTED**

A. In most cases, the GRID model was run with modified inputs to compute the adjustments. In one case, Adjustment 6 - Gas Start Up Costs, the adjustment was computed outside of the model. The Company uses this approach as well, and applies adjustments outside of the GRID model, for example, for inter-hour wind integration and start up fuel costs.

After presenting its initial NPC results in its January 2014 general rate case filing, the Company updated its GRID NPC results on April 10, 2014. Despite the limited amount of time that we have had since the update was filed, our adjustments are based on the Company's updated NPC study results. As discussed below, the OCS may file additional testimony concerning the Company's update during the rebuttal phase.

Finally, the impact of combining results from a series of GRID runs each having individual adjustments will often be different than the impact from one GRID run with all adjustments included in the one run. Once the Commission has approved a set of adjustments, I understand the Company is required to combine all of the approved adjustments into a final compliance GRID run, which may modify the value of specific adjustments.[1]

**Q. PLEASE SUMMARIZE YOUR ADJUSTMENTS.**

A. The following summarizes each adjustment.

**<u>Overview of Net Power Cost (GRID)</u>**

PacifiCorp's updated NPC request of $1.510 billion (total Company) in NPC is overstated by $30.2 million on a total System basis. OCS recommends NPC of $1.480 billion, resulting in a reduction to the Utah allocated revenue requirement of $12.8 million. The specific adjustments recommended by the OCS are shown above in Table 1 and summarized below.

[1] In its May 1, 2012 Order in Docket 11-035-T10, the Commission required the Company to submit a compliance NPC study after a general rate case order is issued for the duration of the EBA pilot program.

**<u>A. Company Update</u>**

**<u>Adjustment 1 - Company Updated NPC</u> -** This incorporates the impact of the Company's update in the total recommended NPC.

**<u>B. Thermal Unit Modeling</u>**

**<u>Adjustments 2 - 4 - Extended Outages</u> -** Three generating units had exceptionally long forced outages in the four-year period that the Company used to develop forced outage rate ("FOR") inputs to GRID. These adjustments reduce the impact of the exceptionally long outages in the four-year average outage rate calculation. It is necessary to correct this problem as it is unrealistic to assume such extreme events will occur once every four years.

**<u>Adjustment 5 - Heat Rate FOR Adjustment</u> -** The Company's GRID model systematically understates the efficiency of generating units, and leads to higher fuel expenses being determined than would actually occur. In part, this is due to GRID's treatment of thermal generating unit forced outage rates as capacity derations. The Company's method of modeling the impact of forced outage rates in GRID eliminates the possibility that any thermal unit could ever operate at its most efficient heat rate, which is unrealistic and drives up fuel expense.

**<u>Adjustment 6 - Gas Startup Energy</u>** - The Company increases net power costs to account for the cost of gas start-up energy; however, it ignores the fact that energy is produced during start-up that is used to serve native load. This adjustment includes the benefit of the energy produced during start up.

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

**<u>Adjustments 7 - Black Hills Power</u> -** The Company models the Black Hills Power ("BHP") contract in a way that overstates the NPC by assuming that BHP will take power in the highest cost hours possible. This adjustment utilizes a more realistic schedule for the contract consistent with historic data.

**<u>D. Transmission Issues</u>**

**<u>Adjustment 8 - Transmission Losses</u> -** The Company calculated transmission losses using a five-year average of the actual losses that occurred over the period 2008-2012. This calculation has been updated to include the five-year period ended December 31, 2013.

**<u>E. Market Caps</u>**

**<u>Adjustment 9</u>** The Company continues to model constraints that restrict GRID's ability to purchase and sell energy to wholesale markets. In the past, intervenors argued that imposing market caps on all markets was artificial and restricted the amount of coal-fired generation below what could have reasonably been produced.[2] These parties argued that only the highly illiquid Mona market should have been limited by a market cap input. Recognizing that these inputs have been disputed in the past, the Company has proposed in this case to remove market caps at Mid-Columbia and Palo Verde. Given that GRID produces coal-fired energy below the historic four year average, the Company should go farther to address this disputed issue, and remove market caps from all but highly illiquid markets such as Mona. Even with this adjustment, coal-fired generation does not increase significantly, and is slightly below the four year average.

**F. Balancing/Overlap Adjustment**

**Adjustment 10** As in prior cases, the OCS recommends that the Company perform a final GRID run, which would include all of the Commission-approved adjustments, and the final screens that are applied to perform proper unit commitment. This adjustment is simply a placeholder to account for the impact caused by combining adjustments and removing overlapping adjustments.

**NPC Update Issues**

With regard to NPC updates, the Company has developed a procedure for revising its filing by making updates that it has used in this and prior proceedings, although the Commission has not adopted a formal update policy. OCS witness Cheryl Murray addresses update policy issues, and I address implementation issues that should be followed in future cases.

[2] Direct Testimony of Mark Widmer (page 4) and George Evans (page 13), Docket 11-035-200, filed June 11, 2012.

## II. NET POWER COSTS AND GRID

**Q. PLEASE DEFINE WHAT NPC IS, AND EXPLAIN HOW THE COMPANY DETERMINES TEST YEAR NPC LEVELS.**

A. NPC is computed as the sum of fuel, transmission wheeling, and purchase power expense less revenue from sales for resale. NPC encompasses FERC expense accounts 501 (fuel), 503 (steam), 547 (other fuel), 555 (purchased power) and 565 (wheeling expense). Account 447 (sales for resale) is a revenue account that is credited against NPC.

The Company uses the GRID model to develop NPC by simulating the least cost operation of the Company's generating units to meet both retail and wholesale load requirements. GRID optimizes the operation of generating units, purchases and sales, and the transmission system used to move power from the source to the various load centers and delivery points. GRID has been used in all of the Company's rate cases and power cost cases since around 2003.

**Q. THE SETTLEMENTS IN THE PRIOR CASE AND PRIOR COMMISSION ORDERS LEFT SOME NPC ISSUES UNRESOLVED. HAS ANY PROGRESS BEEN MADE TOWARDS RESOLVING THESE ISSUES?**

A. Yes. In prior cases there were numerous NPC adjustments, and progress has been made by the Company in adopting adjustments that parties have made such as removal of "must run" modeling on certain combined cycle and combustion turbine units. Despite this progress, NPC remains a dynamic issue, and there are still modeling issues that need to be addressed in this case.

**Q. PLEASE SUMMARIZE THE ADJUSTMENTS IDENTIFIED IN TABLE 1 ABOVE.**

A. The adjustments in Table 1 are grouped by section, with each containing a set of related issues. The following summarizes each of the adjustments.

## A. The Company Update

**Adjustment 1 - Company Update**

**Q. WHY HAVE YOU INCLUDED THE COMPANY UPDATE IN TABLE 1?**

A. The proposed update is listed as the first adjustment to reflect the changes the Company made to its initial filing on April 10, 2014. Our adjustments have been applied to the Company's updated GRID database.

**Q. HAVE YOU COMPLETED YOUR REVIEW OF THESE ADJUSTMENTS?**

A. No we have not. The Company provided a complete update package for 15 updates on April 10th, which only allowed 3 weeks to review the updates prior to when our testimony had to be filed. As a result, we have not had time to fully evaluate the reasonableness of all of the Company's adjustments. Examples of updates still being reviewed include GRID modeling changes for the BAL-002-WECC-2 requirement, which FERC recently approved affecting contingency reserve requirements, and changes associated with the BAL-003-1 standard, which will require additional spinning reserves to be held for frequency response. These are complex matters that the Company has been involved with for several years,[3] but these issues were not incorporated in the GRID modeling until the April 10th update was filed. In the case of BAL-002-WECC-2, Mr. Duvall's Direct Testimony did mention that the Company would incorporate this change in its April 10th updated filing; however, the Company did not mention anything about the BAL-003-1 standard until it supplied its updated filing. We are continuing to evaluate these and the other updates filed on April 10th, and may address these further in the rebuttal phase of the case.

[3] http://www.wecc.biz/standards/development/wecc-0083/default.aspx

## B. Thermal Unit Modeling

**Q. WHAT ARE THE THERMAL UNIT MODELING ISSUES YOU ADDRESS?**

A. I address three issues related to thermal unit modeling: 1) the impact on projected forced outage rates of extended outages that occurred during the historic period; 2) the impact of forced outage rate modeling on heat rates and fuel consumption; and, 3) the impact of incorporating gas start-up costs without including the benefit of the associated energy produced when the gas units start-up.

### Adjustment 2 - 4 - Extended Forced Outages

**Q. ARE OUTAGES AN IMPORTANT DRIVER IN OVERALL NET POWER COSTS?**

A. Yes. Generating units fail randomly and the cost of replacing power with more expensive generating units increases overall net power costs. Production cost models account for the impact of randomly occurring forced outages using different modeling techniques. The GRID model uses the deration approach, based on generating unit forced outage rates that are input into the model. It is important to ensure that forced outage rates are as reasonable as possible, as they are important drivers in the derivation of net power costs.

**Q. DO YOU BELIEVE THAT NORMALIZING ADJUSTMENTS SHOULD BE APPLIED TO THE THERMAL FORCED OUTAGE RATES?**

A. Under certain circumstances, I do. If the historic data reasonably reflects the expected future availability of generating units, then normalizing adjustment are not necessary. However, if the historic data incorporates unusual extended outage events that are unlikely to repeat in the projected period, then the unusual events should be removed from the historic data used to calculate projected outage rates. Consequently, it is important to review all outage events to determine if they were prudent or reasonable for inclusions in the four-year average.

**Q. ARE THERE ANY FORCED OUTAGE RATE NORMALIZING ADJUSTMENTS THAT YOU RECOMMEND BE APPLIED TO THE COMPANY'S GRID INPUTS?**

A. Yes, there are three, related to the Colstrip 4, Lake Side 1, and Gadsby 4 units. The following contains details regarding forced outages at these units that led to the adjustments I am recommending.

**[Begin Confidential]**

| Unit ID | Beg. Date | Hrs. Duration | Lost MWh | NERC Code | Description |
|---|---|---|---|---|---|
| Colstrip 4 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Lake Side 1 Steam Turbine | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| Gadsby 4 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |

**[End Confidential]**

These outages were identified from the minimum filing requirement historic outages data, and were, by far, the longest outages with a large number of lost megawatt hours ("MWH") compared to any of the other unit outages.[4] For example, the Lake Side 1 Steam Turbine outage, which was the shortest outage of the three, was still more than [redacted] times longer than any of the other forced outages that occurred during the historic period.[5] Out of [redacted] forced and maintenance outages that occurred during the historical four-year period at PacifiCorp's thermal units, the average duration of the outages was [redacted] hours; therefore, the three outages of [redacted] each are clearly unusual events.

**Q. IS THERE REASON TO BELIEVE THAT ANY OF THESE OUTAGES WILL RECUR DURING THE PROJECTED PERIOD?**

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[4] Historic outage file - UTGRC14_EOR CONF.xlsx

[5] In the historical outage workpapers provided by the Company, the Lake Side 1 Steam Turbine was referred to as LS3. In addition, the two combustion turbine units at Lake Side 1 were referred to as LS1 and LS2, respectively.

**A.** No there is not. By incorporating these unexpected extended outage events in the calculation of forced outages, these units are made more unavailable in GRID than they would likely be during the July 2014 to June 2015 projected period. Colstrip 4, for example, suffered an [redacted] The root cause analysis indicated that the [redacted][6] As a result of the [redacted] Numerous recommendations for steps to be taken were identified to avoid the observed [redacted] and it appears unlikely that future problems will occur resulting in having to shut the unit down again for another [redacted] days to repair the same problem.

**Q. SHOULD THESE THREE EVENTS BE REFLECTED IN THE NPC BASELINE?**

A. No. Each of these was a rare event and quite unlikely to recur once every four years, as assumed in the Company's four-year moving average calculation. It is unlikely that these events would be representative of conditions expected to occur during the rate effective period. To assume that related problems would occur during the projected period, it would have been likely that related problems would have occurred at other times during the historic period after the unit was repaired. For example, the [redacted] outage at Colstrip 4 occurred from [redacted], at the very start of the four year averaging period. After [redacted] outage occurred, no other related outages appear to have occurred at Colstrip 4 during the remainder of the four year averaging period.[7] As a result, including this event and the other events for Lake Side 1, and Gadsby 4 in the derivation of forced outage rates would result in an inaccurate forecast being produced.

[6] OCS Data Request 2.45.

[7] Based on a review of historic outages searching for NERC cause codes 4215 through 4250

**Q. WHAT IS YOUR RECOMMENDATION?**

A. I recommend that these outages should be removed from the four year averaging period and the outage rates should be re-computed. This is equivalent to assuming that the energy lost during these long outages was the same as the average amount of energy lost for the rest of the historic period. Removing these extended outages provides a much better approach to forecasting future outage rates for the rate effective period. It is quite unrealistic to assume such long outages with such a significant impact will re-occur once every four years at the specific unit, as is the premise underlying the Company's forced outage rate calculation method.

**<u>Adjustment 5 - Heat Rate Curve and Minimum Operating Capacity Adjustment</u>**

**Q. WHAT IS THE PURPOSE OF THIS ADJUSTMENT?**

A As mentioned above, production cost models account for the impact of randomly occurring forced outages using different modeling techniques. The GRID model uses the deration approach, which reduces the capacity of thermal units based on generating unit forced outage rates that are input into the model. Based on the way generating unit capacity and unit efficiency (heat rate) is modeled, the Company's deration modeling approach in GRID systematically overstates heat rates, which results in fuel consumption and net power costs being higher than they should be.

**Q. PLEASE EXPLAIN HOW THE COMPANY MODELS HEAT RATES.**

A. Heat rates represent a thermal generating unit's efficiency of converting fuel input into electrical energy output. Heat rates are measured in units such as MBTU/MWh, which is derived by dividing fuel consumed by energy produced. Heat rates are non-constant and vary non-linearly by capacity level at the generating unit. The best, most efficient heat rate often, though not always, occurs at or near the maximum capacity of each generating unit. This is important because coal units such as PacifiCorp's are frequently dispatched at higher capacity levels. Heat rates curves, commonly referred to as input-output curves, are either developed from tests conducted at the unit by utility personnel, or from design heat rate data provided by the generating unit manufacturer. These heat rate curves establish the relationship between the amount of heat input to the generating unit in order to produce a specified amount of energy output.

**Q. PLEASE EXPLAIN HOW THE COMPANY MODELS FORCED OUTAGES.**

A. As previously discussed, generating units randomly fail and the cost of replacement power when outages occur increases overall net power costs. GRID accounts for random outages using the deration method, in which generating units are derated by the availability of the unit. For example, a 100 MW generating unit with a 20% FOR will have an 80% availability rate (100% minus FOR), and its derated maximum capacity will be 80 MW (80% of 100). GRID's forced outage rate modeling logic restricts this generating unit from ever operating above 80 MW.

**Q. IS THIS AN UNREASONABLE MODELING APPROACH?**

A. The Company's GRID deration approach to forced outage rate modeling is not widely used in production cost models, though it is not an unreasonable approach. For example, GRID has been accepted in all of the states that PacifiCorp has operated in for many years. Furthermore, GRID does properly limit the maximum amount of generation that a unit could possibly produce in a way that is consistent with the actual operation of the unit. In actual operation a low cost unit might be forced offline 20% of the time, but otherwise, it would be possible for it to produce 100 MW every hour that it was available to operate. In a month having 744 hours, the unit with a 20% forced outage rate could possibly operate for 80% of the hours in the month - 80% of 744 hours, or 595.2 hours.

Based on this number of hours, the 100 MW unit could possibly produce as much as 59,520 MWh (100 * 595.2), operating using its most efficient heat rate.

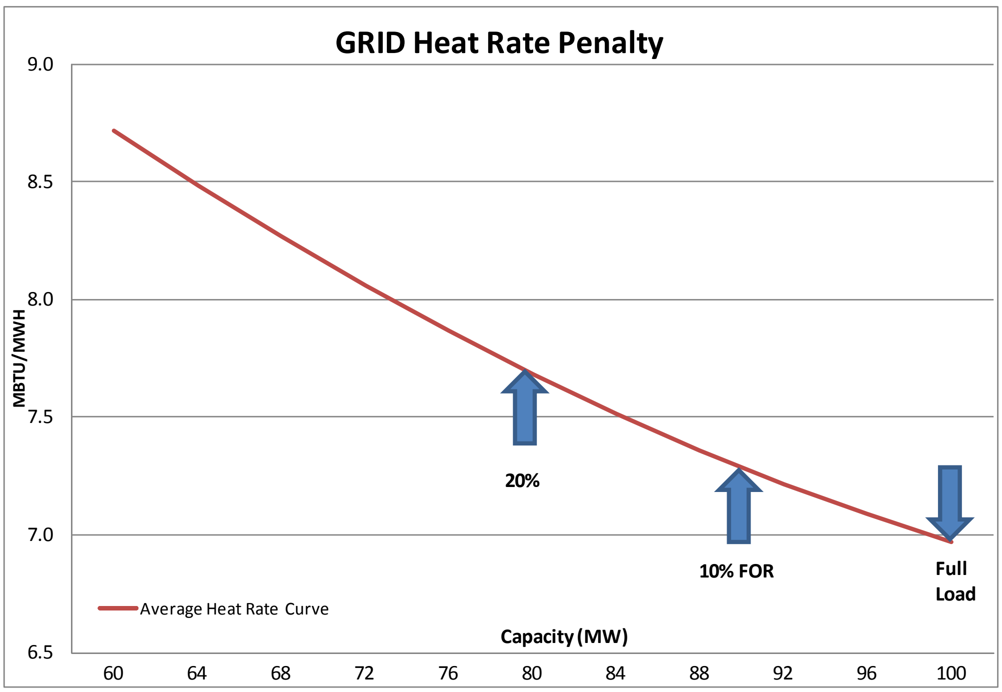
To capture the impact of a 20% forced outage rate, GRID restricts the operation of the 100 MW unit by "trimming" the size of the unit to account for the forced outage rate. In this example, GRID "trims" the 100 MW unit to become an 80 MW (.8 * 100) unit available for all hours of the projected period. By doing this, the energy that the unit could possibly produce is limited in GRID to be no more than 59,520 MWh (80 * 744), which is consistent with the amount of energy the unit could possibly produce in actual operation.

**Q. PREVIOUSLY YOU MENTIONED THAT THE COMPANY'S DERATION FORCED OUTAGE RATE MODELING APPROACH OVERSTATES HEAT RATES. PLEASE EXPLAIN HOW THIS OCCURS.**

A. Since a generating unit typically operates more efficiently closer to its maximum capacity, and since GRID's forced outage rate modeling approach trims the capacity of the unit, GRID never permits the unit to be dispatched using its more efficient heat rates. In the example of the 100 MW unit, GRID trims the unit to operate at no more than 80 MW, and prevents it from dispatching using its more efficient heat rates that would in actual operation occur between 80 and 100 MW. The adjustment I propose revises generating unit heat rate curves to account for the fact that GRID's forced outage rate modeling logic artificially restricts generating units from being able to use their more efficient heat rates.

**Q. CAN YOU PROVIDE A HYPOTHETICAL GRAPHICAL DEPICTION OF THIS PROBLEM IN GRID?**

A. Yes, the chart below shows what happens when a heat rate curve sized for a 100 MW unit is applied to the "trimmed" 80 MW unit. The unit artificially "moves up the heat rate curve" and the efficiency of the unit is reduced. As the forced outage rate increases for a unit, its heat rate increases in the GRID modeling. It is certainly appropriate to limit the amount of energy that could be produced in GRID as the forced outage rate of the unit increases; however, it is not reasonable that a unit should become less efficient just because its forced outage rate increases. This is nothing more than a means to artificially increase a unit's heat rate, which leads to higher fuel consumption, and greater fuel costs.




**Q. HOW HAVE YOU CORRECTED THIS HEAT RATE MODELING PROBLEM?**

A. The necessity for an adjustment has been recognized in previous rate cases by both the OCS and the Division of Public Utilities ("DPU"). Randall Falkenberg for the OCS and George Evans for the DPU both proposed heat rate adjustments in 2012 and in prior cases, and I recommend the same adjustment that Mr. Falkenberg previously proposed. The adjustment I recommend continues to allow the maximum capacity of the unit to be derated so that the amount of energy produced by the unit is limited by the forced outage rate input, just as the Company allows; however, I also shift the heat rate curve so that the unit can continue to rely on its most efficient heat rates even though it will be operating at its new derated maximum capacity. In addition, I also derate the minimum capacity of the unit to mirror the way GRID derates the maximum capacity.

**Q. PLEASE PROVIDE FURTHER EXPLANATION OF THE SHIFT IN THE HEAT RATE CURVE THAT YOU RECOMMEND.**

A. The shift in the heat rate curve is done to change the heat rate at the derated maximum capacity so that it is equivalent to what the heat rate was at the actual maximum capacity. GRID's forced outage rate modeling approach clearly results in restricting generating units from ever being able to operate at their more efficient heat rate levels. The adjustment that I recommend is to modify the formula used to model the generating unit heat rate curve for each unit using the availability rate of the unit. In the example previously discussed, the modeled generating unit heat rate coefficients would be modified using the unit's 80% availability rate. In essence, with this adjustment, the dispatch is constrained so that the generation of the unit is limited based on the derated capacity of the unit, but also, the actual most efficient heat rates of the unit will still be used as the unit is dispatched to higher capacity levels.

**Q. PLEASE PROVIDE FURTHER EXPLANATION OF THE MINIMUM CAPACITY DERATION THAT YOU ALSO APPLY.**

A. Because the maximum capacity is scaled down and the heat rate curve is shifted, the minimum capacity should also be scaled down using the availability of the unit. For example, in the case of the 100 MW unit, with an 80% availability rate, if it has a 40 MW minimum capacity, then the new minimum capacity input for modeling purposes should be 32 MW (.8 * 40). While this minimum capacity input may indeed be less than the minimum capacity the unit can achieve in actual operation, it is set to this value as a modeling convenience. Both adjustments are designed to achieve a more accurate fuel consumption modeling result, while still limiting the unit from producing more than it could possibly produce in actual operations of the unit.

**Q. IS THERE ANOTHER WAY YOU CAN EXPLAIN WHY THE MINIMUM CAPACITY SHOULD ALSO BE SCALED DOWN?**

A. Yes. Modeling the deration of a generating unit to account for forced outages is similar to modeling a generating unit that is jointly owned by two companies, and data for just one company is entered into a production cost model such as GRID. For example, assume that a 100 MW unit with a 40 MW minimum was jointly owned by PacifiCorp and another company, and PacifiCorp wanted to model its share of the unit in GRID. If each company owns 50%, then it would be appropriate to scale down the maximum and minimum capacities of the unit by 50%, and model a 50 MW unit (100 * .5) with a 20 MW (40 * .5) minimum capacity in GRID. Furthermore, it would be necessary to adjust the heat rate curve to ensure that when the unit in GRID operates at maximum capacity (50 MW), the efficiency would be the same as the actual efficiency of the full unit operating at 100 MW. The same would hold true for adjusting the heat rate curve so that when it operates in GRID at 20 MW, it would achieve the same heat rate as the full unit would when actually operating at 40 MW.

**Q. HAS THE MODELING TECHNIQUE YOU RECOMMEND BEEN USED BY ANY OTHER UTILITY IN PACIFICORP'S REGION?**

A. Yes, it is my understanding that in an Oregon proceeding, in which the Oregon Public Utility Commission ("OPUC") investigated generating unit forced outage rate modeling, testimony was presented stating that Portland General Electric (“PGE”) uses a similar modeling approach in its power cost model, MONET.[8] In that proceeding, OPUC Staff supported use of the MONET approach and objected to PacifiCorp's deration method.

[8] OPUC Investigation Into Forecasting Forced Outage Rates for Electric Generating Units, OPUC Docket No. UM 1355.

Staff's testimony noted that "When PacifiCorp's model derates the maximum capacity of the unit, (i.e. 600 MW to 540 MW) the corresponding heat rate indicates the plant is less efficient than it actually is at the operating maximum, and creates an unrealistic scenario in the GRID model."[9] Staff also stated on the same page, "PGE's model recognizes that the derating of the unit in the model, associated with forced outages, has no impact on the unit's efficiency at converting fuel into energy."

**Q. HAS THIS ISSUE BEEN ADDRESSED IN PRIOR UTAH CASES?**

A. Yes, though the Commission has never made a final decision regarding the merits of the issue. The issue was fully litigated in Docket 09-035-23 and the Commission continued to accept the Company methodology, but only because it wanted the matter to be studied further before it reached a final conclusion. The Commission even suggested there might be alternatives to the Company's method that should be considered. In asking for more analysis, the Commission's Final Order at page 57 discussed the following potential alternative:

> For example, one alternative could be proportionally adjusting or compressing the heat rate curves so when a plant is running at its full derated capacity it will have a heat rate associated with the non-derated full capacity, and when it is running at its minimum capacity the heat rate will be the non-adjusted minimum one.

An attempt was made to address this issue through discussions involving the Company, the DPU, and the OCS, however, no resolution was reached. At this point, the Company continues to rely on its faulty approach, which results in inflated fuel costs. Once again, the OCS opposes the Company's method, and recommends use of the adjustment that I have discussed.

[9] OPUC Docket No. UM 1355, Supplemental Reply Testimony of Kelcey Brown, Staff Exhibit No. 300 at 19 (August 13, 2009).

**<u>Adjustment 6 - Gas Start-Up Energy</u>**

**Q. PLEASE EXPLAIN THE GAS START-UP ENERGY ADJUSTMENT.**

A. The Company increases net power costs using an adjustment after GRID has been run to account for the cost of starting up gas units; however, it ignores an associated benefit that occurs when the units are started up. The Company includes about $[redacted][10] in start-up costs for gas units, but ignores the energy that is produced when units are started up. Combined cycle units typically experience a relatively large number of start-ups, and therefore produce a consequential amount of energy when they are started up.

**Q. WHAT ADJUSTMENT DID YOU DEVELOP TO INCLUDE ENERGY PRODUCED DURING THE START-UP OF GAS UNITS?**

A. I performed an analysis that resulted in a post-GRID adjustment associated with energy produced during start-up. First, I reviewed the number of start-ups incurred by the Lake Side 1 and 2, Currant Creek 1, Chehalis, and Hermiston Units as described in the Company's start-up workpaper.[11] Then based on an analysis of historic data over the 48 month period between July 2009 and June 2013, I determined an average amount of energy produced by each combined cycle unit during start-up. I then priced the start-up energy and reduced net power costs by this amount. To be conservative, I priced the start-up energy at the average cost of coal-fired generation over the test period. Adjustment 6 in Table 1 incorporates the benefit associated with including this start-up energy adjustment.

[10] Note that in the Company's initial January filing, start-up energy costs were about [redacted] Now that the Company has filed its updated case, the number of start-ups have increased significantly, and the Company's start-up energy cost has doubled to [redacted]

[11] UTGRC14s_Startup Costs (131108) CONF.xlsx

## C. Long Term Contracts

**Adjustment 7 - Black Hills Power Shaping**

**Q. PLEASE EXPLAIN HOW THE BLACK HILLS POWER CONTRACT IS MODELED IN GRID.**

A. Black Hills Power ("BHP") is a “call option sale” contract. Call option contracts allow the purchaser the right to pre-schedule energy deliveries based on expected market prices and/or the purchasers’ requirements. BHP is modeled as an energy limited sale contract with a required maximum amount of energy that must be purchased from PacifiCorp each week, and a minimum amount of energy that must be purchased from PacifiCorp each month. It appears that in GRID, the Company allows GRID to schedule the contract primarily during the highest cost hours allowed for the specified period.

**Q. IS THE RESULTING HOURLY ENERGY SCHEDULE REASONABLE?**

A. Not entirely. The way the Company schedules energy to High Load and Low Load hours does not align as well as could be done compared to the four-year historic data. The Company's GRID run schedules 70% of the energy to the High Load hours, which is somewhat more than what was historically scheduled to High Load hours. Historically, about 61% of the energy was scheduled during the High Load hours, and the rest was scheduled to the low load hours.

**Q. HOW HAVE YOU REVISED THE HOURLY ENERGY SCHEDULE?**

A. I assigned a constant amount of energy to each hour such that the low load hours received approximately 40% of the total amount of energy, and I allowed GRID to schedule the remaining amount of energy to the highest cost hours, which all occur during the high load hours. That resulted in the desired 40%/60% low load/high load split occurring, consistent with historical data, and ensured that a portion of the high load hour energy was assigned to the highest cost hours, similar to what the Company had done in scheduling all of the energy. Scheduling energy to the low load and high load hours on the basis of historical data with this adjustment is also reasonable since the Company does something similar in determining the delivery points of the energy that it sells to BHP. The Company relies on historical data to determine the percent of energy delivered to BHP by delivery point. Therefore, it is also reasonable to use historical data to determine the split of energy between low load and high load hours. Table 1 contains the value of this Adjustment 7.

## D. Transmission Issues

### Adjustment 8 - Transmission Losses

**Q. HOW DID THE COMPANY DETERMINE LOSS FACTORS IN GRID?**

A. The Company used a simple five-year average of annual calendar year losses from the period January 2008 through December 2012. However, recent transmission investments have been quite substantial and, as a result, losses should be declining. More recent data reflects this decline in losses.

**Q. DID PACIFICORP USE MORE RECENT HISTORICAL DATA FOR DEVELOPING OTHER TEST YEAR DATA INPUTS?**

A. Yes, in the Company's initial filing, it developed GRID data inputs for items such as planned outage rates, forced outage rates, hydro data, etc, based on historical data that ended in June 2013. Furthermore, when the Company updated its GRID database in the updated filing it made on April 10, 2014, it developed Short Term Firm transaction data inputs based on information that only became available after January 1, 2014.

**Q. WHAT DO YOU PROPOSE TO DO REGARDING THE LOSS FACTOR INPUT?**

A. I recommend that a revision be made to the loss factor calculation reflecting more recent data that was available at the time the Company updated its filing on April 10, 2014. Instead of averaging loss factor data for the five year period ending 2012, the Company should average data for the five year period ending 2013. In discovery response OCS DR 2.53 - 1st Supplemental, the Company supplied more recent data covering the 2013 calendar year. I have recomputed loss factors for the five year period ending 2013, and updated GRID inputs to reflect those adjusted loss factors. Adjustment 8 in Table 1 contains the results based on the loss factor adjustment.

## E. Market Caps

**Adjustment 9 - Market Caps**

**Q. PLEASE EXPLAIN WHAT MARKET CAPS ARE AND HOW THEY ARE USED IN GRID.**

A. Market caps are limits PacifiCorp models in GRID to restrict the amount of economic transactions that could otherwise occur between the Company and trading partners at wholesale markets including the California Oregon Border ("COB"), Four Corners, Mead, and other markets. Market caps are in addition to transmission limits that are input, which also restrict economic transactions by limiting the amount of power that can flow across links. PacifiCorp claims that without modeling market caps, market sales in GRID would exceed the demand for PacifiCorp's low cost resources that actually could be made. As a result, PacifiCorp's GRID market cap modeling construct ends up limiting the efficient operation of its units.

**Q. HOW DOES PACIFICORP DEVELOP MARKET CAP INPUTS?**

A. PacifiCorp sets the caps equal to the 48-month average volume of short term transactions for a particular market less the volume of executed sales entered into for the test period and input to GRID. Even if transmission capacity exists, GRID's ability to decide whether to make economic market sales is restricted, without any evidence that a robust market would not exist during the projected period.

**Q. ARE MARKET CAPS APPROPRIATE?**

A. Market cap modeling has received a significant amount of criticism by intervenors, who have found it to be a highly questionable modeling construct. In the past, intervenors argued that imposing market caps on all markets was artificial and restricted the amount of coal-fired generation below what had historically been produced.[12] Recognizing that these inputs have been disputed in the past, the Company has proposed in this case to remove market caps at Mid-Columbia and Palo Verde. I do not believe market caps are reasonable, except in cases in which the markets are expected to be highly illiquid and have few trading partners, such as the Mona market. Removing market caps from the Palo Verde and Mid-Columbia markets is a step in the right direction, but the Company has not demonstrated that other markets such as Mead, COB or Four Corners will be as highly illiquid as Mona, and limiting those markets simply serves to artificially reduce the economic value of PacifiCorp's generating units.

**Q. DO YOU BELIEVE MARKET CAPS ARE NECESSARY IN GRID TO LIMIT THE AMOUNT OF COAL-FIRED GENERATION THAT IS PRODUCED?**

A. No I do not. While the Company's updated test period GRID results indicate that coal-fired generation is below, but close to the historic four year average generation ([redacted]), the generation results with market caps removed from all markets but Mona are within [redacted] of the historic four year average.[13] Incorporating this adjustment lowers net power costs, and results in more economic operation of the Company's units, without causing unwarranted and excessive use of its coal-fired units. Furthermore, PacifiCorp already includes other data in GRID that restrict the amount of economy sales that could occur. Transmission constraints restrict flows on interfaces within transmission limits,

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[12] Direct Testimony of Mark Widmer (page 4) and George Evans (page 13), Docket 11-035-200, filed June 11, 2012.

[13] This comparison excludes Carbon and Naughton, because they do not operate during the entire projected test period, while they were operated for the entire historic period.

and the Company's official forward price curves ("OFPC") limit the amount of sales based on the prices available at market hubs. This is demonstrated by the fact that the Company updated its OFPC in GRID on April 10th, to its latest March 31, 2014 forecast, and the amount of system balancing transactions dropped by about [redacted]% from [redacted] GWh per year to [redacted] GWh a difference of [redacted] GWh.[14]

**Q. WHAT IS YOUR RECOMMENDATION FOR MARKET CAPS?**

A. I do not oppose including market caps on markets that are highly illiquid, and PacifiCorp's decision to remove the Palo Verde and Mid-Columbia market caps is a step in the right direction, however, I do not believe this is sufficient. Unless PacifiCorp demonstrates that the markets are highly illiquid like the Mona market, and the amount of coal-fired generation in GRID is unrealistic, then I recommend that market caps should also be removed from the other markets, as well. The impact of removing the market caps, Adjustment 9, is shown on Table 1.

## <u>F. Balancing/Overlap Adjustment</u>

**<u>Adjustment 10 - Final Balancing/Overlap Adjustment</u>**

**Q. WHAT IS THE PURPOSE OF THE FINAL BALANCING ADJUSTMENT/OVERLAP ADJUSTMENT?**

A. This adjustment provides a placeholder for the final balancing adjustment that will be performed once the final Commission approved adjustments are determined. NPC Adjustments can affect each other. For example, a change in outage rates will impact derated capacity/heat rate modeling in GRID. Since we do not now know the final adjustments that the Commission will approve, it is only possible at this time to provide an estimate of the final Balancing/Overlap adjustment. Furthermore, when the final

[14] Comparison of the initial filed NPC case versus the April 10 U08 update case.

adjustments are performed, the Company also has to apply final screens that help ensure that the proper unit commitment is performed. The impact of the Balancing/Overlap adjustment placeholder (Adjustment 10) is shown in Table 1.

## III. NPC UPDATE

**Q. DO YOU HAVE ANY COMMENTS REGARDING THE UPDATING PROCESS THAT HAS THUS FAR TAKEN PLACE?**

**A.** Yes. The Commission's scheduling order states that PacifiCorp would file net power cost updates on April 10, 2014, which the Company has now done. This has provided 21 days for intervenors to review the updated filing, conduct analyses, submit discovery, analyze responses, and finalize testimony. While this schedule was agreed upon at the start of this proceeding, the experience has led to recommendations that both OCS witness Cheryl Murray and I discuss in our respective testimony.

**Q. ARE THERE PRACTICAL ISSUES THAT MUST BE CONSIDERED IN PROCESSING UPDATES DURING A CASE?**

**A.** Yes. Updates pose certain practical problems for parties attempting to address the Company's filings. 21 days is a relatively short amount of time to submit and review discovery, conduct analyses, and file testimony, especially considering enough time must be allowed for submitting testimony for internal review before it is filed. The Company supplied 15 new NPC studies, some involving new dispatch operating procedures. The effort to review the Company's updated filing is not limited strictly to the updates the Company makes, but also requires consideration of potential updates that the Company did not make.

**Q. WHAT IS YOUR RECOMMENDATION FOR FUTURE GENERAL RATE CASES CONCERNING FILING UPDATES TO NPC REVENUE REQUIREMENTS?**

**A.** In this proceeding the Company filed the NPC update 97 days after filing its initial case, leaving intervenors just 21 days to analyze the updates and file testimony. In essence, 82% of the time elapsed before the update was filed, leaving parties just 18% of the time to review the updates. This is not equitable, and I recommend in the future if an update is allowed it should be filed with at least six weeks remaining between receipt of complete updated NPC information and the date intervenor testimony is due. In general, such updates should be limited to just changes in third-party contracts for fuel, power and transmission services, and correction of errors. The Company should not change the time frames, methodologies or assumptions relied upon in developing NPC inputs as it would be difficult to review these type of changes in the available time.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes it does.