PUBLIC

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power For Authority to Increase its Retail Electric Utility Service rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.	))))))	DOCKET NO. 09-035-23 DPU EXHIBIT 6.0

PRE-FILED DIRECT TESTIMONY

GEORGE W. EVANS

ON BEHALF OF THE

UTAH DIVISION OF PUBLIC UTILITIES

October 8, 2009

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INTRODUCTION

Q. Please state your name, business address, employer, and current position or title for the record.

A. My name is George W. Evans, and my business address is 358 Cross Creek Trail, Robbinsville, North Carolina 28771. I am a Vice President with Slater Consulting.

Q. For whom are you providing testimony in this case?

A. I am providing testimony on behalf of the Utah Division of Public Utilities (DPU or Division).

Q. Please describe your education and work experience.

A. I received a Bachelor of Science in Applied Mathematics from the Georgia Institute of Technology in 1974. In 1976, I received a Master of Science in Applied Mathematics, also from the Georgia Institute of Technology. My area of concentration was probability and statistics. In 1980 I joined Energy Management Associates, Inc. (EMA), the company responsible for the development of the premier electric utility modeling tools, PROMOD®, PROSCREEN®, PROVIEW® and MAINPLAN®. While at EMA, I worked with some fifty (50) major electric utilities in the United States and Canada in the application of these modeling tools for generation expansion planning, the development of net power costs, fuel budgeting, the analysis of power purchases and the development of optimal maintenance schedules for generating units.

In 1989 I left EMA to join GDS Associates, Inc., a consulting firm located in Marietta, Georgia. At GDS I was a principal and the Manager of System Modeling. In this position I was primarily responsible for performing analyses and presenting expert testimony concerning integrated resource planning, the forecasting of system production costs, developing estimates of the likelihood of service interruptions, developing estimates of replacement power costs and related activities.

In August of 1997 I left GDS to join Slater Consulting as a Vice President. A copy of my résumé is included in DPU Exhibit 6.1.

Q. Where have you testified before?

A. I have provided expert testimony on 35 previous occasions, before the public utility commissions in Pennsylvania, Georgia, Michigan, Arkansas, South Dakota, Colorado, Illinois, Mississippi, Alabama, Delaware, South Carolina and Oklahoma; and also before the FERC (Federal Energy Regulatory Commission), and in state court and federal court. A complete list of the proceedings that I have testified in is in DPU Exhibit 6.1.

Q. **Have you appeared before the Public Service Commission of Utah (Commission) in the past?**

A. No, I have not.

PURPOSE OF TESTIMONY

Q. **What is the purpose of your testimony in this proceeding?**

A. The purpose of my testimony is to identify and quantify certain recommended adjustments to the Company's Net Power Costs (NPC) as proposed in the current Utah rate case. In this rate case PacifiCorp, which does business in Utah as Rocky Mountain Power (the Company), proposes a rate increase of $66.9 million over the forecasted test period July 1, 2009 through June 30, 2010. My recommended adjustments total approximately -$40 million, with approximately -$16 million allocated to Utah.

Q. **What is the amount that the Company has filed as a Total Company NPC for the test year?**

A. As identified in the direct testimony of Company witness Mr. Gregory N. Duvall (page 2, line 38), the Company's normalized NPC for the test year are approximately $999 million, with approximately $410 million of these costs allocated to Utah.

Q. **What recommendations are you making in this filing?**

A. I am recommending six adjustments to the Company's filed NPC, as summarized below:

1. Coal Forced Outage Rates – An adjustment of -$16,800,867 (-$6,895,251 for Utah) to reflect coal unit forced outage rates in line with national averages.

2. Planned Outages on Coal Units – An adjustment of -$338,957 (-$139,112) for Utah) to cause the planned outage schedule to better reflect historical planned outage schedules.

3. Wyodak Heat Rate Correction – An adjustment of -$1,006,149 (-$412,934 for Utah) to reflect a correction to the heat rate curve for the Wyodak coal plant.

4. Wind Integration Costs – An adjustment of -$19,776,992 (-$8,116,683 for Utah) to reduce the Company's wind integration charge to only the inter-hour charge.

5. Startup Energy – An adjustment of -$2,065,518 (-$847,710 for Utah) to recognize energy produced during the startup of gas generating units.

6. Coal Costs – An adjustment to be quantified at a later date, reflecting consistent inflation assumptions and updated commodity prices. A quantification cannot be produced at this time, due to the Company's failure to provide electronic copies of the coal pricing spreadsheets. We continue to seek this information and will address the issue again in rebuttal testimony.

Detailed descriptions of each of these adjustments are presented below.

COAL FORCED OUTAGE RATES

Q. What are forced outage rates?

A. Forced outage rates quantify the percent of time that a generating unit is unavailable because of unforeseen, that is, not planned, outages and reductions in capability. For example, if a generating unit has a forced outage rate of 10%, the unit can be expected to be available for operation 90% of the time at full capacity, exclusive of any planned outages.

Q. What problem have you found with the Company's historical forced outage rates?

A. Some of the Company's coal generating units have experienced exceptionally high forced outage rates when compared to units of similar size around the country. DPU Confidential Exhibit 6.2 compares the historical forced outage rates of the Company's coal units to the average forced outage rates taken from the NERC Generating Availability Data System (GADS) for units of similar size. In some cases, the Company's coal units have experienced forced outage rates that are more than 50% greater than the national average.

Q. What recommendation are you making concerning coal unit forced outage rates?

A. I'm recommending that the average national forced outage rates (from GADS) be used in place of the unit specific historical forced outage rates currently used by the Company. Continued use of the unit specific historical forced outage rates embeds these excessive forced outage rates in customer rates. My recommendation would both reward the Company for better than average forced outage rates, and incent the Company to improve the performance of those coal units with high forced outage rates.

Q. Could the age of the Company's coal units explain the high forced outage rates?

A. No – the average age of the Company's coal units is 35 years as of 2008 (as shown in DPU Confidential Exhibit 6.2), while the age of the coal units included in the GADS data average 38 years.

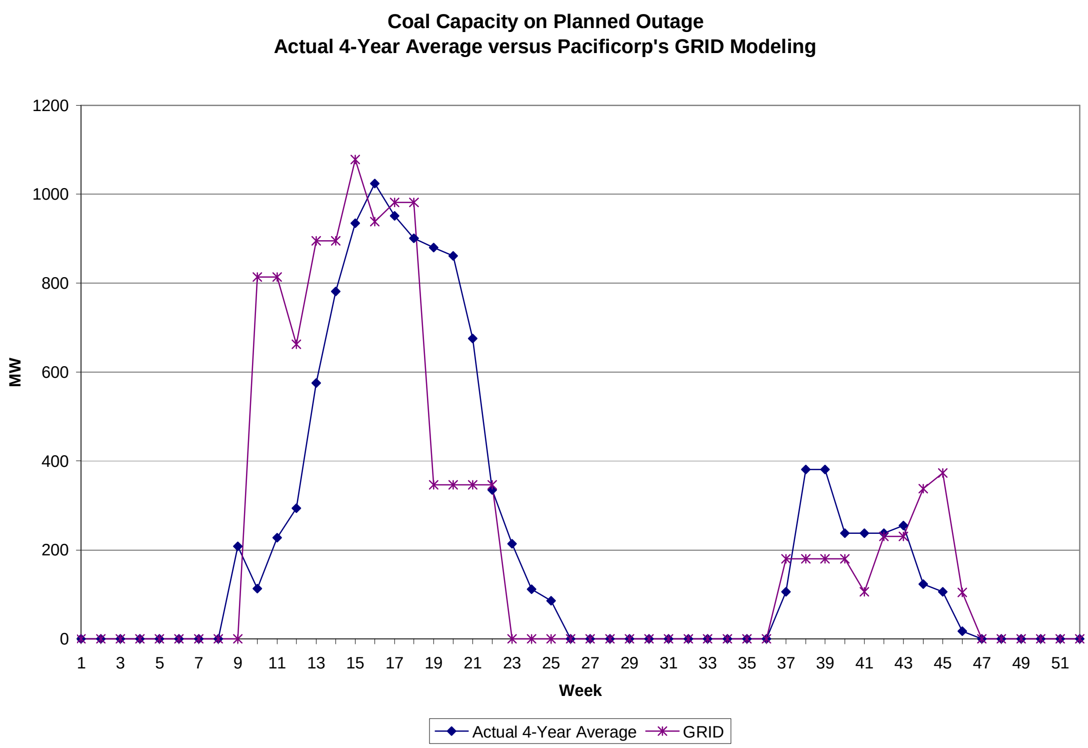
Q. How have you quantified your recommended adjustment?

A. I reran the Company's GRID model, using the GADS forced outage rates for each coal unit, in place of the unit specific historical forced outage rates used by the Company. The modified GRID results were then used to develop a modified NPC. The dollar adjustment is -$16,800,867, with -$6,895,251 for Utah.

PLANNED OUTAGES ON COAL UNITS

Q. Why have you recommended an adjustment for the planned outages on coal units?

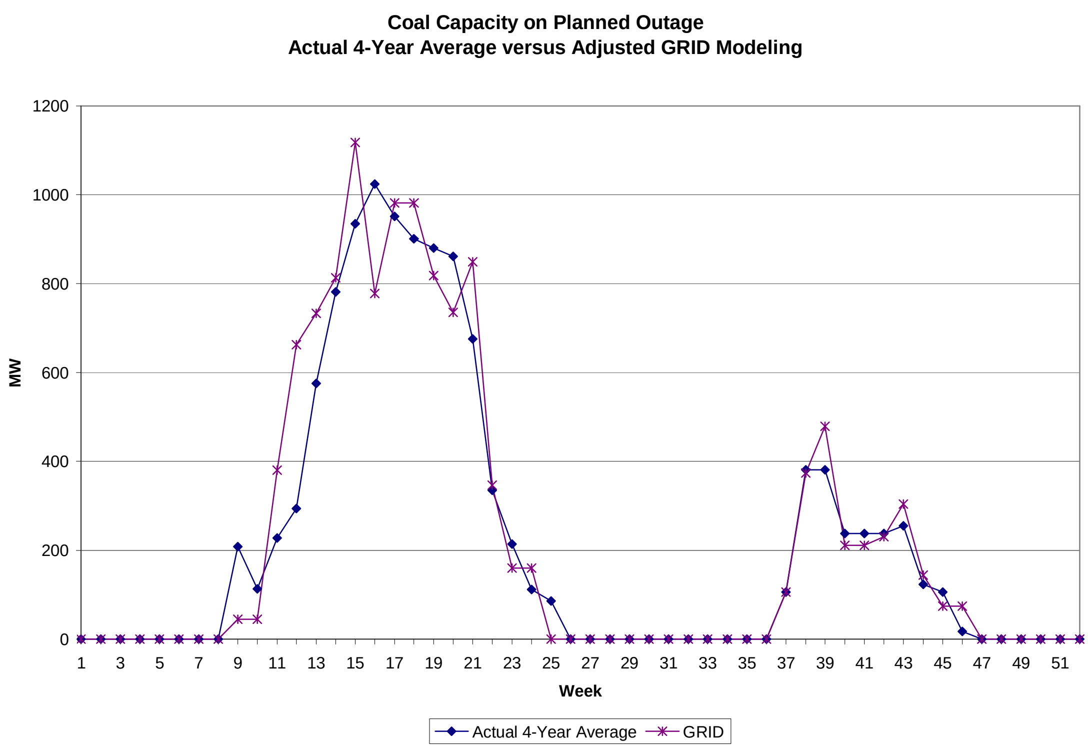
A. The Company has created a normalized planned outage schedule (see Mr. Duvall's direct testimony, line 201 on page 9 to line 259 on page 12) that is used in the GRID model to produce the filed NPC. The chart below compares coal capacity on planned outages in the GRID schedule to the average of the actual planned outages over the previous four calendar years.



The data for this chart were compiled from information supplied by the Company in response to data requests OCS 3.17 and MDR-B 2.57. The chart shows that the planned outage schedule used by the Company in GRID differs dramatically from the actual planned outage schedules.

Q. **How have you corrected this problem?**

A. I manually adjusted the planned outage schedule for use in GRID so that the GRID schedule would align more closely with the actual historical outages. The following chart compares the adjusted GRID schedule to actual schedules.



Q. **How did you quantify this adjustment?**

A. I reran the GRID model using the adjusted planned outage schedule, and developed a modified NPC, using the adjusted GRID results. The dollar adjustment is -$338,957, with -$139,112 for Utah. Costs are reduced using the adjusted outage schedule because additional planned outages are shifted into low cost periods.

WYODAK HEAT RATE CORRECTION

Q. What is the issue involving Wyodak?

A. There is a discrepancy between the actual historical heat rate at the plant and the heat rate produced by the GRID model.

Q. How did the Wyodak heat rate issue arise?

A. A comparison of the actual historical heat rate at the Wyodak coal plant to the heat rate produced by the GRID model showed that, over the past five calendar years, Wyodak's heat rate has averaged 11.63 MMBtu/MWh, while the Company's GRID model shows an average heat rate of 12.271 MMBtu/MWh (see page 12 of Mr. Duvall's Exhibit GND-1).

Q. What source did you use for actual historical data?

A. I utilized the data filed by the Company in the FERC Form 1 for the calendar years 2004-2008. These data are shown in DPU Exhibit 6.3.

Q. Have you questioned the Company on this issue?

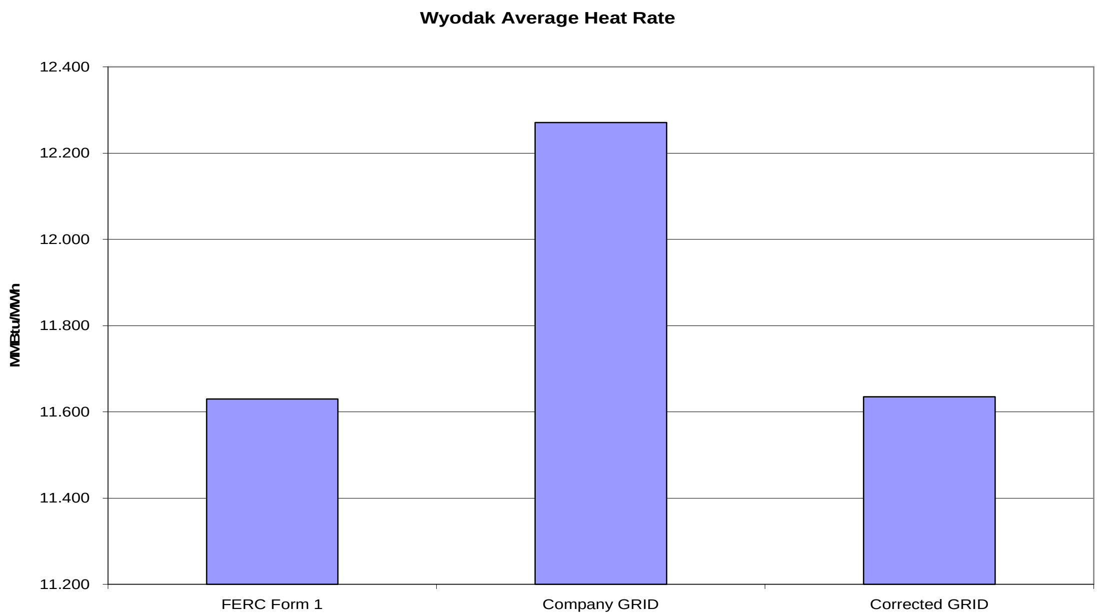
A. Yes, I have. The question and the Company's response are shown in DPU Exhibit 6.4. In its response, the Company claims that the high Wyodak heat rate is a result of "unit dispatch", that is, the simulated generating levels at which the unit was operated within GRID.

Q. Is the Company's explanation a reasonable one?

A. No – the heat rate curve developed by the Company for Wyodak will produce average heat rates above 12.0 MMBtu/MWh at any level of unit dispatch. The Company's Wyodak heat rate curve is shown in DPU Confidential Exhibit 6.5. Using the Company's heat rate curve for Wyodak, it would be impossible to produce heat rates that approach actual historical heat rates.

Q. Have you been able to ascertain the problem with the Company's heat rate curve for Wyodak?

A. Yes – Wyodak is a jointly owned generating unit, with the Company having an 80% ownership. Along with other data, the Company uses annual historical generation and fuel burn data to develop the heat rate curves for use within GRID. It appears that for two historical years, the Company used 80% of the total unit generation while using 100% of the total fuel burn. Correcting this problem, and re-running GRID with the corrected heat rate curve, produces an average heat rate for Wyodak of 11.635 MMBtu/MWh, which lines up nicely with historical data, as shown in the following chart.



Q. Was your quantification of this adjustment based on this GRID result?

A. Yes, it was. I replaced the Company's Wyodak heat rate curve in GRID with the corrected Wyodak heat rate curve, and produced the adjusted NPC from the adjusted GRID results. The dollar quantification of this recommended adjustment is -$1,006,149, with -$412,934 for Utah.

WIND INTEGRATION COSTS

Q. What wind integration costs has the Company included in NPC for Company owned wind facilities?

A. The Company has included over $28 million for wind integration costs, which is based on a charge of $6.91 per megawatt hour. That is, for each megawatt hour of energy produced by the Company's owned wind facilities, the Company has included $6.91 in NPC.

Q. Were these charges produced by the GRID model?

A. No, they were not. The Company adds these charges to the total costs produced by GRID. This is worrisome in itself, since the Company claims that GRID is an accurate simulation of the operation of the Company's generating system, and these claimed costs are additional fuel costs and purchase power costs that are supposed to arise during the operation of the generating system.

Q. Do these claimed wind integration charges line up with historical charges?

A. The Company is unable to produce any recorded historical wind integration charges, so comparing these claimed charges with actual costs is impossible. See the Company's response to DPU Data Request 34.2, which is included here as DPU Exhibit 6.6.

Q. How did the Company come up with its $28 million charge for wind integration?

A. The Company performed several statistical analyses using spreadsheets to estimate the hourly wind integration charge, which the Company claims to be $6.91 per megawatt hour. The first analysis estimated the inter-hour (or hour to hour) costs, which came to $2.08 per megawatt hour. The second analysis estimated the intra-hour (or within the hour) costs, which came to $4.83 per megawatt hour. Adding these two costs gives the total claimed wind integration charge of $6.91 per megawatt hour.

Q. What problems do you see in the Company's analyses?

A. There are a number of significant problems in the Company's intra-hour analysis. The primary problem is that the Company has assumed that additional reserves must be added to accommodate wind resources, without ever evaluating the actual level of reserves that would be carried without the wind resources.

Q. Please explain.

A. Reserves, including those for regulation, are carried on an electric generating system to allow the system to quickly respond to intra-hour changes in customer demand, and interruptions on the system, such as generator failures and transmission problems. The Company is claiming that wind resources will always require additional reserves (in the form of regulating reserves) due to the uncertainty of wind generation. However, nowhere in the analysis does the Company consider whether the reserves carried to cover other uncertainties are sufficient to cover the added uncertainty of wind. So the Company has never established the need for the claimed additional reserves. Instead the Company has assumed that there will always be such a need. In fact, the Company is unable to produce any evidence that additional reserves are being carried in response to added wind capacity – see the Company's response to DPU Data Request 34.4 in DPU Exhibit 6.7.

Q. What level of reserves does the Company claim to need for wind generation?

A. The Company claims that it must carry intra-hour reserves equivalent to 23% of installed wind capacity; compared to 5% for hydro and 7% for thermal resources. Clearly the Company's reserve requirement for wind is excessive.

Q. What other issues do you have with the Company's intra-hour analysis?

A. The Company essentially assumes that any change in wind generation must be covered by other generating units. This problem is best illustrated with excerpts from Mr. Duvall's testimony. On page 17, in lines 370-373 of his direct testimony, Mr. Duvall states that "As generation from the wind plants increases during the hour, other plants must reduce generation (regulate down), and as generation from the wind plants decrease during the hour, other plants must increase generation (regulate up)." Then on page 21, in lines 450-452 of his direct testimony, he claims that "When wind energy moves up within an hour, other generation resources are required to reduce their output to compensate for this intra-hour energy deviation." Neither of these statements are necessarily correct. In fact, just as wind generation varies during an hour, customer demand varies during an hour, hydro generation varies during an hour, and even fossil generation will vary within an hour. One has to consider the net impact of all of these potential variations before claiming that other generating resources must compensate for all changes in wind generation. The Company has concentrated solely on the variability of wind, ignoring all other sources of intra-hour variability.

Q. What other problems do you see in the Company's intra-hour analysis?

A. The Company's analysis is based on 10-minute wind data from the period September 2008 through April 2009, only eight months of data, and does not include any summer data. In addition, two additional wind facilities are expected to begin commercial operations in October 2009, and are not included in the basic data for this analysis.

Q. How did the Company model the wind facilities that started operations in October 2009?

A. Lacking any operating data for these new wind plants, the Company assumed that the new wind facilities would operate just as the existing wind facilities operate, that is, the Company increased wind generation proportionally, assuming the new facilities would operate identically as existing facilities.

Q. Is this a problem?

A. Yes, it is. Wind facilities in different areas will follow different hourly patterns of production, with one facility possibly increasing generation when another facility is decreasing generation. The Company has assumed that this is not the case with these new wind facilities. Instead the Company has made the worst possible assumption – that the new wind facilities will precisely follow the hourly generating patterns of the existing wind facilities.

Q. Are other DPU witnesses testifying on this issue?

A. Yes - please see DPU witness Dr. William Powell's testimony for additional discussion on the intra-hour wind integration analysis.

Q. What are you recommending on wind integration charges?

A. The DPU is recommending that the Commission only allow the inter-hour wind integration charge of $2.08 per megawatt hour. This is an adjustment of -$19,776,992, with -$8,116,683 for Utah.

STARTUP ENERGY

Q. What is startup energy?

A. When a gas-fired generating unit begins operating after an idle period, there is a short period in which the plant is producing electricity, but has not yet reached its typical minimum operating level. This period is known as the startup period, and the energy produced is the startup energy.

Q. What is the issue with this startup energy?

A. In the requested NPC, the Company includes the cost of this startup energy for its Lakeside, Currant Creek, Chehalis and Hermiston gas-fired plants, but does not include any credit for the startup energy itself. That is, the cost of the fuel that is burned to produce the startup energy is included, but the energy itself is ignored. The ratepayer is asked to pay for the fuel without receiving the benefit of the energy produced.

Q. What do you recommend?

A. I recommend that a credit be included in NPC for the startup energy, at the average price of coal energy. This method would assume that the startup energy results in a reduction of coal energy, which is a reasonable assumption, and was suggested by the Company in the previous rate case. The startups generally occur in early morning hours, causing coal units to reduce output. My computation of the adjustment is shown in DPU Confidential Exhibit 6.8. The recommended dollar adjustment is -$2,065,518, with -$847,710 for Utah.

COAL COSTS

Q. What issue do you have concerning coal costs?

A. To develop coal costs in the test year, the Company makes assumptions concerning general inflation, escalation of wages and benefits, the cost of commodities such as diesel fuel, natural gas and other petroleum products. Comparing the Company's responses to Data Request OCS 6.1 and OCS 6.7, it appears that the Company has used inconsistent assumptions for general inflation. In the Company's response to DR OCS 6.1, the inflation forecast for 2009 is [redacted] and [redacted] for 2010, while [redacted] is used for general inflation in the Company's response to DR OCS 6.7. In addition, the forecasted costs of commodities such as natural gas have recently fallen. For example, actual natural gas prices in July and August 2009 at the Henry Hub were approximately [redacted] lower than what the Company predicted.

Q. Have you updated the Company's coal costs to reflect these changes?

A. No, we have not. The Company has not provided the spreadsheets in electronic form that would allow such an update so, accordingly, we are waiting for the Company to produce revised coal costs in response to our data request. We have submitted a data request (DPU DR 50.1) asking the Company to update coal costs, and may submit an adjustment in rebuttal testimony.

Q. Does this complete your testimony?

A. Yes it does.