

Rocky Mountain Power  
Docket No. 13-035-184  
Witness: Dana M. Ralston

BEFORE THE PUBLIC SERVICE COMMISSION  
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

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Direct Testimony of Dana M. Ralston

Generation O&M

January 2014

1 **Q. Please state your name, business address, and present position with**  
2 **PacifiCorp dba Rocky Mountain Power (“the Company”).**

3 A. My name is Dana M. Ralston. My business address is 1407 West North Temple,  
4 Suite 320, Salt Lake City, Utah 84116. My present position is Vice President of  
5 Thermal Generation. I am responsible for the coal, gas, and geothermal resources  
6 owned by the Company.

7 **Qualifications**

8 **Q. Please describe your education and business experience.**

9 A. I have a Bachelor of Science Degree in Electrical Engineering from South Dakota  
10 State University. I have been the Vice President of Thermal Generation for  
11 PacifiCorp Energy since January 2010. Prior to that, I held a number of positions  
12 of increasing responsibility with MidAmerican Energy Company for 28 years  
13 within the generation organization including the plant manager position at the  
14 Neal Energy Center, a 1,600 megawatt generating complex. In my current role, I  
15 am responsible for operation and maintenance of the thermal generation fleet.

16 **Purpose and Overview of Testimony**

17 **Q. What is the purpose of your testimony?**

18 A. The purpose of my testimony is to explain and support the level of operating and  
19 maintenance (“O&M”) costs included in this rate case. The Company is  
20 experiencing increasing costs necessary to operate and maintain the Company’s  
21 thermal generation resources as follows:

22 (1) The addition of mercury controls on several of the units to comply with the  
23 Mercury and Air Toxics Standard (“MATS”) as issued by the Environmental

24 Protection Agency (“EPA”),  
25 (2) environmental permit changes that the Company must comply with,  
26 (3) increased utilization of the plants and changes in the sulfur content and BTU  
27 of the fuel,  
28 (4) the addition of second block of generation at the Lake Side plant, and  
29 (5) general changes in what maintenance is performed and inflationary cost  
30 impacts across our generation fleet.

31 **Q. Please summarize your testimony.**

32 A. The Company’s thermal generation fleet non-labor<sup>1</sup>, non-overhaul O&M  
33 expenses are projected to be approximately \$196.1 million for the 12 months  
34 ending June 30, 2015 (“Test Period”), as compared to the historical base period  
35 expense for the 12 months ending June 30, 2013 (“Base Period”), of \$175.7  
36 million. As described in detail in Company witness Mr. Steven R. McDougal’s  
37 Exhibit RMP\_\_\_\_(SRM-3), Tab 4, page 4.9.1, the escalation of costs from the  
38 Base Period to the Test Period is partially explained by the inflation adjustment  
39 included in the case for non-overhaul generation O&M costs of \$5.5 million.  
40 However, upon careful review of plant level operating conditions the Company  
41 believes that an overall increase in non-labor, non-overhaul O&M costs of \$20.3  
42 million (over the Base Period) is essential to maintain the plants. This is an  
43 increase of \$14.8 million over the level of inflation.

44 Within the overall increase in costs, a major driver is related to the O&M  
45 impacts associated with environmental compliance activities. With the installation

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<sup>1</sup> O&M costs for the joint-owned, partner-operated plants on Mr. McDougal’s Exhibit RMP\_\_\_\_(SRM-3), Tab 4, page 4.9.1 include labor costs, while the Company operated plants treat labor costs in a separate adjustment.

46 of environmental control equipment to control mercury, the Company's operating  
47 costs are increasing due to chemicals and reagents that are required to operate the  
48 equipment. Additionally, operating costs are increasing due to coal quality issues  
49 addressed by Ms. Cindy A. Crane. Furthermore, the Company anticipates  
50 increased costs due to the addition of the second block of generation at Lake Side  
51 and increases in required maintenance at some of the plants. Finally the  
52 imposition of costs related to jointly owned, partner-operated generation stations  
53 by the other owners of such stations. These specific activities underlie the need  
54 for a higher level of generation O&M costs in rates.

55 **Environmental Cost Increases**

56 **Q. Please explain the impact of the increase in the use of scrubber reagents and**  
57 **chemicals on operating costs.**

58 A. The successful operation of the environmental control equipment is dependent  
59 upon chemicals to perform the emission reductions. There are several things that  
60 will impact the amount of reagent used such as permit levels, sulfur content, BTU  
61 of the fuel, and plant utilization. Also the new MATS regulation will require  
62 additional reagent used to achieve compliance with the new regulation.

63 **Q. Which plant's operating costs are impacted by environmental permit**  
64 **changes?**

65 A. Hunter Unit 1 will experience a permit change during the Test Period. The  
66 previous permit required the unit achieve a SO<sub>2</sub> removal efficiency of 80 percent  
67 (which is approximately 0.16 lbs. per million BTU). The new permit requires the  
68 unit to meet a 30-day emission rate of 0.12 lbs. per million. This decrease in

69 permitted emission rate causes the plant to use more lime in the scrubber to  
70 achieve the new permit level emissions rate which will increase forecasted costs  
71 approximately \$0.6 million.

72 **Q. Please explain which plants will experience an increase in utilization and fuel**  
73 **changes that will increase reagent use.**

74 A. Hunter plant will experience an increase in the sulfur content of the coal from  
75 0.62 percent sulfur during the base year to 0.68 percent sulfur during the test year  
76 as explained in the testimony of Ms. Crane.<sup>2</sup> This increase in sulfur will require an  
77 increase in the use of lime and increase forecasted costs approximately \$0.57  
78 million.

79           Huntington plant will also experience a similar increase in the sulfur  
80 content of the coal from 0.51 percent sulfur during the Base Period to 0.64 percent  
81 sulfur during the Test Period as described by Ms. Crane. Also during the Test  
82 Period the plant is forecasted to experience an increase in utilization and a  
83 decrease in fuel BTU. These changes will result in a total increase of lime used to  
84 meet SO<sub>2</sub> emission permit levels and are forecast to increase costs approximately  
85 \$1.36 million.

86           The Jim Bridger plant is forecasted to see an increase in utilization and  
87 sulfur which will increase the amount of scrubber reagent used. The increase in  
88 the sulfur content of the coal from 0.58 percent sulfur during the Base Period to  
89 0.59 percent sulfur during the Test Period as described by Ms. Crane. Total O&M

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<sup>2</sup> Ms. Crane's testimony identifies the sulfur content related to specific sources. The numbers herein are sulfur content based on the overall blended coal supply at the plants.

90 costs will increase approximately \$0.74 million to meet SO<sub>2</sub> emission permit  
91 levels.

92 The Wyodak plant is forecasted to see an increase in utilization and sulfur  
93 which will increase the amount of scrubber reagent used. The increase in the  
94 sulfur content of the coal from 0.50 percent sulfur during the Base Period to 0.56  
95 percent sulfur during the Test Period as described by Ms. Crane. Total O&M  
96 costs will increase approximately \$0.23 million to meet SO<sub>2</sub> emission permit  
97 levels.

98 **Q. Please explain which plants will require controls to meet compliance with the**  
99 **MATS regulation that has been issued by the EPA.**

100 A. The new MATS regulations will go into effect on April 16, 2015, and all plants  
101 must be in compliance at that time. The plants that will need additional controls to  
102 achieve compliance are Naughton, Jim Bridger, Wyodak and Dave Johnston  
103 plants. The additional controls will require the use of reagents specifically for the  
104 removal of mercury. Total O&M costs will increase approximately \$4.3 million  
105 due to the addition of the mercury controls at these plants.

106 **Non-Reagent Chemical Increases**

107 **Q. Please explain what plants will experience an increase in non-reagent**  
108 **chemicals and why.**

109 A. The Jim Bridger plant will increase the amount of chemicals required to treat the  
110 water from the Jim Bridger mine due to an increase in the amount of water  
111 received from the mine. The amount of mine water treated will increase  
112 approximately 950 gallons per minute. This will increase the amount of chemicals

113 required to treat the water so it can be used for cooling water at the plant. The  
114 approximate cost increase due to the additional chemicals required to treat the  
115 water is \$0.44 million.

116 **Q. Please explain the cost impacts of the addition of the second block of**  
117 **generation at the Lake Side plant.**

118 A. In 2014 the second block of generation will go into service at the Lake Side plant  
119 and the O&M costs associated with that block are included in the Test Period. The  
120 additional costs related to the second block of generation are approximately \$1.55  
121 million and includes chemicals, non-chemical materials, and water fees.

#### 122 **Additional Maintenance**

123 **Q. Please explain the increases in maintenance and the drivers behind the**  
124 **change.**

125 A. During the Test Period additional maintenance will occur at the Hunter and Dave  
126 Johnston plants. The Hunter plant will experience an additional coal mill rebuild  
127 due to the amount of coal consumed and the timing of the rebuild. This will  
128 increase costs by approximately \$0.22 million at the Hunter plant. The Company  
129 expects an increase of approximately \$1.1 million at the Dave Johnston plant due  
130 to the timing of the work and increased scope of the ash pond cleaning during the  
131 Test Period. Part of the increase, \$0.30 million, is associated with the increased  
132 scope of the ash pond cleaning. The remaining \$0.8 million of the increase is due  
133 to the timing of the projects that were done during the Base Period with respect to  
134 the Test Period. During the calendar years 2012, 2013, 2014, and 2015 the  
135 average of the amount spent or planned on O&M projects when compared to the

136            respective calendar year is fairly level. The major difference is the timing of the  
137            actual expenditures in the Base Period with respect to the Test Period.

138    **Jointly-Owned, Partner-Operated Generation Plant O&M Costs**

139    **Q.    Which plants are partially owned by PacifiCorp, but operated by others?**

140    A.    The Company has a joint-ownership interest in, but does not operate the Camas,  
141            Cholla, Colstrip, Craig, Hayden and Hermiston plants. The operating companies  
142            of these plants establish the operating budgets necessary to maintain and operate  
143            the plants and the Company, as a joint owner, is obligated to pay its share of these  
144            costs.

145    **Q.    What is the forecasted increase in expense related to these plants?**

146    A.    The Company is forecasting an increase of \$9.5 million in O&M costs associated  
147            with these jointly-owned plants, or an increase of \$7.7 million over the general  
148            inflation included in the case of \$1.8 million as seen in Mr. McDougal's Exhibit  
149            RMP\_\_\_(SRM-3) page 4.9.1. Generally, the operators at these plants are facing  
150            the same types of operating issues and costs the Company is facing. The  
151            Company works with the operating companies to review and comment on the  
152            costs forecasted and incurred by these plants, but is obligated to pay its share of  
153            the costs incurred. One the of cost increases at the Cholla plant is the addition of  
154            mercury reagent due to the addition of mercury controls as required by the MATS  
155            regulation. The approximate cost of this reagent increase is \$1.1 million. Cholla  
156            will also experience an additional coal mill rebuild due to the amount of coal  
157            consumed and the timing of the rebuild. This coal mill rebuild will increase costs  
158            approximately \$0.47 million. Further, the costs of the common projects for the



159 entire Cholla site have increased due to increased maintenance. These projects  
160 provide services to all the units at the Cholla site. The major drivers of the  
161 common projects increase are additional maintenance on the slurry disposal  
162 pumps, additional coal fueling system maintenance and other small miscellaneous  
163 projects. The total increase due to the common costs is approximately \$0.80  
164 million. Additionally, some of the differences between the Base Period and the  
165 Test Period at Cholla is due to timing. During 2013, the Cholla site had two major  
166 overhauls in the spring. One of the overhauls occurred on Cholla 4 so several of  
167 the common projects costs were delayed until the last half of 2013.

168 **Summary and Conclusion**

169 **Q. Please summarize your testimony.**

170 A. The Company is experiencing a changing environment with respect to the  
171 permitted emission levels allowed by state and federal regulations, the quality of  
172 fuel that is used to generate electricity, and the utilization of the plants. The  
173 changes listed above are causing the Company to incur higher O&M costs. In  
174 addition, changing operating conditions and increased costs at partner-operated  
175 generation stations warrant a higher level of O&M expense in the future. A non-  
176 labor (except for partner-operated plants), non-overhaul level of O&M expense of  
177 \$196.1 million (total Company) is crucial to properly maintain and operate the  
178 plants. This level of expense should be approved by this Commission and Utah's  
179 share of these costs should be included in rates.

180 **Q. Does this conclude your direct testimony?**

181 A. Yes.