

Docket No. 20000-__-ER-11
Witness: Mark R. Tallman

BEFORE THE WYOMING PUBLIC SERVICE
COMMISSION

ROCKY MOUNTAIN POWER

Direct Testimony of Mark R. Tallman

December 2011

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 Mark R. Tallman. My business address is 825 NE Multnomah, Suite
4 2000, Portland, Oregon 97232. My present position is Vice President of
5 Renewable Resources. I am responsible for hydro-powered and wind-powered
6 generation resources 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 Oregon State
10 University and a Masters of Business Administration from City University of
11 Seattle. I am also a Registered Professional Engineer in the states of Oregon and
12 Washington. I have been the Vice President of Renewable Resources since
13 January 2011. Prior to that, I was Vice President of Renewable Resource
14 Acquisition from December 2007 to January 2011 and Managing Director of
15 Renewable Resource Acquisition from April 2006 to December 2007. I have
16 worked at the Company for more than 26 years in a variety of positions of
17 increasing responsibility including: the commercial and trading organization; the
18 engineering organization; and the retail organization (as a District Manager).

19 **Purpose and Overview of Testimony**

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

21 A. The purpose of my testimony is to describe the increases in costs related to non
22 labor related operations and maintenance (“O&M”) activities for the Company’s
23 wind and hydro generation resources which contribute to the need for the rate

1 relief requested in this case. My testimony also describes when the Company
2 plans to provide updated wind-powered generation resource capacity factor
3 information as directed by the Commission in the 2009 general rate case (Docket
4 No. 20000-352-ER-09).

5 **Q. Please summarize your testimony.**

6 A. The Company's non labor related wind generation O&M costs are projected to
7 increase approximately \$4.9 million over the historical base year ending June 30,
8 2011. The Company's non labor related hydro generation O&M expenses are
9 projected to increase approximately \$4.2 million over the base year. A more
10 granular breakdown of hydro and wind O&M is shown in Mr. Brian S. Dickman's
11 Exhibit RMP___(BSD-2), pages 4.11.2 and 8.11.1.

12 My testimony describes how the cost projections were developed and
13 identifies the key cost drivers for these increases. While there is an overall net
14 increase in hydro and wind O&M, I will address both increases and decreases
15 within these two categories.

16 **Wind-Powered Generation Resources**

17 **Q. Please describe the primary areas of changing costs related to wind-powered
18 generation resources.**

19 A. The primary areas of cost increases and decreases related to O&M of wind-
20 powered generation resources are: (1) materials; (2) third party contracts; and (3)
21 oil changes.

22 **Q. What is the net impact of these changing O&M costs?**

23 A. The net impact of test year O&M costs compared to the base year is shown in the

1 table below.

O&M Category	Test Year – Base Year (\$ million)
Materials	\$4.6
Third Party Contracts	(\$2.9)
Oil Changes	\$3.5
Other	(\$0.3)
Net Total	\$4.9

2 **Q. What is the increase in materials cost associated with?**

3 A. The increase in materials cost for wind generation is primarily driven by several
4 wind projects which will no longer have warranty agreements in effect during the
5 test year. As part of a wind turbine warranty, the manufacturer supplies
6 replacement parts. Post-warranty, the Company must purchase replacement parts.

7 **Q. Which wind projects are impacted by warranties that will no longer be in**
8 **effect during the test year?**

9 A. Ten of the Company's 13 wind projects have warranties that will have expired
10 going into the test year or will expire during the test year. The Seven Mile Hill,
11 Seven Mile Hill II, High Plains, McFadden Ridge I, Glenrock, Rolling Hills and
12 Glenrock III wind projects will be off warranty for the entire test year. The
13 Dunlap I, Marengo and Marengo II wind projects have warranties that expire
14 during the first half of the test year. Foote Creek I is the only wind project that
15 will have a warranty agreement in effect following the test year.

1 **Q. How did the Company determine the level of cost during the test year for**
2 **replacement parts and materials?**

3 A. The Company used historical costs to arrive at a cost estimate for materials on a
4 per turbine basis. This estimate was then utilized for the projects with turbines out
5 of warranty during the test year. Because the Dunlap I, Marengo, and Marengo II
6 warranties expire during the test year, the number of turbines out of warranty is
7 higher during the test year as compared to the base year.

8 **Q. Please explain the cost decreases related to third party contracts.**

9 A. The net decrease in expense related to third party contracts is driven by new
10 O&M contracts at many of the Company's wind plants and the expectation that
11 road maintenance will be lower during the test year. The net decrease also
12 includes an assumption that an O&M contract for Marengo and Marengo II
13 expiring early in the test year can be replaced at a monthly cost lower than
14 experienced during the base year. Conversely, the net decrease includes an
15 increase in annual O&M costs during the test year for the Dunlap I wind project.
16 Dunlap I began operations during the base year so only a partial year's expense
17 was incurred. A full year's contract expense for Dunlap I is included in the test
18 year.

19 **Q. How did the Company determine the level of expense during the test year**
20 **associated with third party contracts?**

21 A. The Company utilized the combination of historical actual costs by project and
22 contract category combined with costs related to committed contracts applicable
23 during the test year.

1 **Q. Please explain the expense increases related to wind turbine oil changes.**

2 A. Consistent with the manufacturer's recommended maintenance schedules, routine
3 oil changes will be performed at nine of the Company's 13 wind projects during
4 the test year.

5 **Q. How did the Company determine the level of costs during the test year
6 associated with oil changes?**

7 A. The cost per turbine of the most recent oil change activity performed by
8 contractors prior to the base year was used as the source of information to
9 estimate the cost of oil changes during the test year.

10 **Hydro-Powered Generation Resources**

11 **Q. Please describe the changes in hydro-powered generation O&M costs that
12 impact the test year.**

13 A. The primary areas of cost level increases related to O&M of hydro-powered
14 generation resources are: (1) Federal Energy Regulatory Commission ("FERC")
15 fees; (2) costs to implement and comply with the FERC license issued for the
16 Lewis River hydroelectric project; (3) costs to implement and comply with the
17 FERC license issued for the Umpqua River hydroelectric project; and (4) costs to
18 implement and comply with the Klamath River Hydroelectric Settlement
19 Agreement ("KHSA").

20 **Q. What is the net impact of these items on O&M costs?**

21 A. The net impact of test year O&M costs compared to the base year is shown in the
22 table below.

O&M Category	Test Year – Base Year (\$ million)
FERC fees	\$1.3
Lewis River FERC license compliance	\$1.0
Umpqua River FERC license compliance	\$0.8
KHSA	\$0.5
Other	\$0.6
Net Total	\$4.2

1 **Q. What is driving the increase in FERC fees?**

2 A. The increased FERC fees are associated with higher FERC land use fees and
3 higher FERC administration fees. In the case of the land use fees, PacifiCorp
4 participated in a successful industry challenge of FERC’s process to revise the fee
5 determination methodology. Because of this successful challenge, the new land
6 use fee structure did not become effective during the base year, but is expected to
7 be effective during the test year. During the FERC challenge, the Company
8 accrued expenses for increased land use fees. The accrued expense reversal due to
9 the successful challenge took place in early 2011 resulting in an abnormally low
10 level of annualized expense appearing in the base year. The cost associated with
11 FERC land use fees in the test year is based on the revised methodology FERC is
12 seeking via a notice of proposed rulemaking (“NOPR”) process. FERC is basing
13 its proposed land use fees on a U.S. Bureau of Land Management methodology.
14 This will result in higher FERC land use fees during the test year.

1 **Q. What is driving the increase in FERC administration fees?**

2 A. FERC administration fees are determined by FERC and are intended to recover
3 FERC's funding requirement by allocating costs to entities that hold FERC
4 hydroelectric licenses. FERC allocates its costs by invoicing the Company
5 annually.

6 **Q. How did the Company determine the level of costs for FERC fees during the**
7 **test year?**

8 A. For the FERC land use fees, the Company used the invoice amount proposed by
9 FERC in its 2009 revised fee schedule which was vacated in early 2011 due to a
10 successful appeal by PacifiCorp and other licensees. In a NOPR issued November
11 22, 2011, FERC proposes to again revise its fee schedule applicable to Federal
12 lands within the boundaries of FERC licensed projects. For the FERC
13 administration fees, the Company used historical actual costs as the basis for
14 predicting FERC's invoice applicable during the test year.

15 **Q. What is the increased cost associated with the Lewis River hydroelectric**
16 **license?**

17 A. To implement and comply with the Lewis River license issued by FERC, the
18 Company has acquired wildlife mitigation lands and is investing in a fish passage
19 system designed to collect, trap and haul juvenile and adult anadromous fish
20 around the three Lewis River dams. These compliance measures result in higher
21 O&M costs to manage the newly acquired forest lands, operate the fish passage
22 system and operate fish transport vehicles which haul juvenile fish downstream
23 and adult fish upstream. In addition, this category also includes increased costs to

1 provide Lewis River recreation services to the public in compliance with FERC
2 license requirements and to maintain aging recreational facilities.

3 **Q. How did the Company determine the level of cost associated with the Lewis**
4 **River hydroelectric license during the test year?**

5 A. Costs for wildlife lands are based on costs to manage like lands as applied to the
6 newly acquired lands. For fish passage operations beginning during the test year,
7 costs were estimated using similar operational systems found at PacifiCorp's
8 currently operating fish hatcheries. Fish transportation cost is based on the
9 estimated number of daily truck trips correlated with the expected timing of
10 migrating fish. Costs for recreation pertain to an enhanced campsite reservation
11 system to account for increasing user demand. The estimated cost for the
12 reservation system is based on comparison with similar state and utility systems
13 that use outside contracted systems. The costs to maintain the aging infrastructure
14 are based on previously completed like work.

15 **Q. What is the increased cost associated with the Umpqua River hydroelectric**
16 **license?**

17 A. The Company is investing in a number of improvements to its North Umpqua
18 River hydroelectric project to implement and comply with the license issued by
19 FERC. Key amongst these improvements is installation of fish passage facilities
20 at the Company's Soda Springs dam and installation of a structure so fish can
21 bypass the Slide Creek plant. The increase in O&M costs is to evaluate the
22 environmental performance of these new facilities as well as costs to address
23 National Historic Preservation Act requirements related to a cultural site.

1 **Q. How did the Company determine the level of costs associated with the**
2 **Umpqua River hydroelectric license during the test year?**

3 A. The costs associated with these O&M activities required in the test year are based
4 on prior evaluation efforts at other similar facilities. With respect to the cultural
5 site, the Company developed a curation plan in consultation with the Oregon State
6 Historic Preservation Office to survey applicable areas and curate artifacts. The
7 plan will be implemented in the test year. The cost of the plan was based on past
8 experience for like activities.

9 **Q. What are the incremental costs in the test year associated with the KHSA?**

10 A. The incremental costs are predominantly associated with required hatchery
11 funding. Under the terms of the KHSA, the Company is obligated to increase its
12 funding of the Iron Gate Hatchery from 80 percent to 100 percent. Similarly, a
13 Hatchery and Genetics Management plan for Iron Gate Hatchery is under
14 regulatory review by the National Marine Fisheries Service. The hatchery plan is
15 expected to further increase costs during the test year as new programs and
16 practices at the hatchery are required to be implemented. Finally, under the
17 KHSA, PacifiCorp is obligated to undertake a study of options for continuing to
18 meet hatchery production goals in the Klamath basin for an eight-year period
19 following the time when the Iron Gate dam is envisioned to be removed under the
20 terms of the KHSA. Cost associated with this hatchery study also drives an
21 increase in costs during the test year.

1 **Q. How did the Company determine the level of costs associated with the KHSA**
2 **during the test year?**

3 A. The costs in the test year were determined using the Company's hatchery funding
4 obligation in the KHSA as well as estimates of the costs to implement the Iron
5 Gate Hatchery and Genetics Management plan. The plan includes measures for
6 genetic broodstock management testing, spawning surveys, and fish testing
7 procedures. Committed contract amounts for the hatchery production study were
8 used to determine costs that will be incurred during the test year.

9 **Capacity Factor Reporting**

10 **Q. Will the Company be providing updated wind-powered generation resource**
11 **capacity factor information?**

12 A. Yes, the Commission directed the Company in the 2009 general rate case (Docket
13 No. 20000-352-ER-09) as follows:

14 "We therefore direct that the Company work with the Commission Staff to
15 establish a consistent set of data to be gathered by the Company and
16 provided to the Commission in future rate proceedings that will allow the
17 Commission to make meaningful comparisons between the actual
18 operating capacity factor of the Company's wind generation facilities and
19 the capacity factor upon which the Company based its decision to pursue
20 those projects. In accomplishing this task, the Company and the
21 Commission Staff shall identify the best industry practices and employ
22 them in their work."

23 In response to this directive, the Company will provide an update of annual
24 capacity factor information during the rebuttal phase of this case. Actual annual
25 capacity factors for wind project operations in calendar year 2011 will not be
26 known until the first quarter of 2012. Preliminary forecasts suggest the actual
27 capacity factors in 2011 for the majority of wind projects will be above the

1 normalized annual forecasts upon which the Company based its decision to
2 pursue those projects.

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

4 A. Yes.