

1 **Q. Please state your name and business address with Rocky Mountain Power**
2 **(the Company), a division of PacifiCorp.**

3 A. My name is Brian S. Dickman and my business address is 201 South Main, Suite
4 2300, Salt Lake City, Utah, 84111.

5 **Qualifications**

6 **Q. What is your current position at the Company and what is your employment**
7 **history?**

8 A. I am currently employed as the manager of revenue requirement for the Company.
9 I have been employed by the Company since 2003 including positions in revenue
10 requirement and regulatory affairs. Prior to joining the Company, I was employed
11 as an analyst for Duke Energy Trading and Marketing.

12 **Q. What are your responsibilities as manager of revenue requirement?**

13 A. My primary responsibilities include the calculation and reporting of the
14 Company's regulated earnings or revenue requirement, application of the inter-
15 jurisdictional cost allocation methodology, and the explanation of those
16 calculations to regulators in the jurisdictions in which the Company operates.

17 **Q. What is your educational background?**

18 A. I received a Master of Business Administration from the University of Utah with
19 an emphasis in finance in 2002 and a Bachelor of Science degree in accounting
20 from Utah State University in 2001. I completed the Utility Management
21 Certificate Program at Willamette University and I have also attended various
22 educational, professional and electric industry-related seminars.

23 **Q. Have you testified in previous regulatory proceedings?**

24 A. Yes. I have testified before the Idaho Public Utilities Commission and the
25 Wyoming Public Service Commission.

26 **Purpose of Testimony**

27 **Q. What is the purpose of your direct testimony?**

28 A. My direct testimony explains and supports the Company's application to recover
29 the increased revenue requirement of \$39.0 million for two major plant additions,
30 namely, the Populus to Ben Lomond transmission line and the Dunlap I wind
31 project. I explain the Company's proposal to adjust rates effective January 1,
32 2011, to begin collecting the price increases related to this filing and the
33 Company's first major plant addition filing in Docket No. 10-035-13, and I
34 explain the Company's proposal to begin amortizing and collecting the balance of
35 revenue requirement deferred between July 1 and December 31, 2010, related to
36 Docket No. 10-035-13. In addition to my testimony, several Company witnesses
37 provide testimony supporting the development of the projects included in this
38 filing, along with the expected costs and benefits. I will identify these Company
39 witnesses and the subject of their respective testimony.

40 **Q. Please explain the circumstances that gave rise to this filing.**

41 A. In the Company's most recent general rate case, Docket No. 09-035-23, the
42 Company and intervening parties reached an agreement May 14, 2009, that
43 specified a filing schedule for major plant addition cases in 2010 and the
44 Company's next general rate case in 2011. The settlement agreement was
45 approved by the Public Service Commission of Utah ("the Commission") June 1,

46 2009. Paragraph 10(a) of that agreement states:

47 10. Single Item Rate Cases.

48 a. Ben Lomond to Terminal Transmission Line Segment and Dave Johnston
49 Scrubber Projects. The Company anticipates that (i) the capital additions of
50 scrubbers to the Dave Johnston Power Station will be completed by May 2010
51 and (ii) the Ben Lomond to Terminal Transmission Line Segment will be
52 completed by June 2010. No projected costs or revenues associated with the
53 foregoing projects will be included in the Company's 2009 General Rate Case.
54 The Company intends to file an application on or after February 1, 2010 for
55 single item rate recovery of the foregoing capital projects pursuant to Utah Code
56 Anno. § 54-7-13.4 (the "Act"). The Parties agree not to oppose the Company's
57 right to file or time of filing (assuming consistency with the 90 and/or 150 days
58 stated in the Act) of the Company's application for approval of rate recovery for
59 the foregoing projects. All Parties reserve and retain the right to take or make any
60 and all substantive positions, claims or objections going to the merits, prudence
61 (if a prudence review has not already been made under the Energy Resource
62 Procurement Act) or amount of recovery in connection with such filings.

63 b. Ben Lomond to Populus Transmission Line Segment and 2009R RFP
64 Resource Selection Process. The Company anticipates that (i) the Ben
65 Lomond to Populus Transmission Line Segment will be completed by
66 December 2010, and (ii) a resource selection will have been made and
67 implemented in the 2009R RFP resource selection process by November
68 2010. The Company intends to file an application on or after August 3, 2010
69 for single item rate recovery of the foregoing capital projects pursuant to the
70 Act assuming, with respect to the later project, that the 2009R RFP resource
71 selection process results in a capital project to be included in rate base. The
72 Parties agree not to oppose the Company's right to file or time of filing
73 (assuming consistency with the 90 and/or 150 days stated in the Act) of the
74 Company's application for approval of rate recovery for the foregoing
75 projects. All Parties reserve and retain the right to take or make any and all
76 substantive positions, claims or objections going to the merits, prudence (if a
77 prudence review has not already been made under the Energy Resource
78 Procurement Act) or amount of recovery in connection with such filings.

79 Consistent with that agreement, in February 2010, the Company filed an
80 application to address the cost recovery of the costs associated with pollution
81 control equipment at Dave Johnston Unit 3 and the Ben Lomond to Terminal
82 transmission line. On June 15, 2010, the Commission issued an order approving
83 the stipulation allowing for the deferral of an annual amount of \$30.8 million. The
84 Company's current application is the second of the major plant additions filings
85 planned for 2010 and addresses the costs related to the Populus to Ben Lomond

86 transmission line and the Dunlap I wind project.

87 **Q. Do the investments in this application qualify for alternative cost recovery**
88 **for major plant additions as outlined in Utah Code Section 54-7-13.4?**

89 A. Yes. One percent of the Company's Utah rate base approved by the Commission
90 in Docket No. 09-035-23 is \$46.3 million and each of the plant additions exceeds
91 this threshold. Additionally, the filing is being made within eighteen months of
92 final order in Docket No. 09-035-23 as required by the statute.

93 **Revenue Requirement**

94 **Q. What is the revenue requirement related to the two major plant additions**
95 **addressed in this application?**

96 A. The following table summarizes the overall requested revenue requirement for
97 each of the projects, allocated to Utah:

\$ millions

| | |
|---|----------------|
| Populus to Ben Lomond Transmission Line | \$ 31.4 |
| Dunlap I Wind Plant | \$ 7.6 |
| Total Revenue Requirement | <u>\$ 39.0</u> |

98 **Q. Please explain how the revenue requirement of the plant additions was**
99 **prepared.**

100 A. The revenue requirement of each plant addition was calculated using the same
101 model and methods employed by the Company in its general rate cases. Each
102 plant addition was treated as an incremental adjustment to a "base case" revenue
103 requirement for the Company's Utah jurisdiction. The Company utilized the
104 Jurisdictional Allocation Model ("JAM") to allocate the various individual
105 revenue requirement components to the state of Utah and compute the net

106 increase in revenue requirement for each project. The working model used to
107 prepare these pages has been included in folder D.1 of the Filing Requirements
108 CD.

109 **Q. What is the return on equity (“ROE”) used in this application?**

110 A. The cost of capital included in this filing is consistent with the outcome approved
111 by the Commission in Docket No. 09-035-23, which includes an ROE of 10.6%.

112 **Q. What is the method currently approved for allocating total Company
113 revenue requirement to Utah?**

114 A. Total Company revenue requirement components are allocated among the
115 Company’s jurisdictions using the Revised Protocol allocation method, as
116 approved by the Commission in Docket No. 02-035-04. However, pursuant to the
117 stipulation reached between the Company and participants in the Multi-State
118 Process, and approved by the Commission, Utah rates are currently limited to the
119 lesser of the amount derived using the Revised Protocol method or the amount
120 derived using the Rolled-In method multiplied by 101 percent (the Rate
121 Mitigation Cap).¹ The rate change in Docket No. 09-035-23 was calculated using
122 the capped revenue requirement based on the Rolled-In allocation multiplied by
123 101 percent.

124 **Q. What method of cost allocation was used to determine the incremental
125 impact of the major plant additions in this filing?**

126 A. I have computed the incremental revenue requirement related to the major plant
127 additions in this filing on a Rolled-In basis. This calculation is done using Rolled-

¹ According to the stipulation rates will be set on the lesser of: (i) Rolled-In multiplied by 101.00 percent, or (ii) Revised Protocol, plus a rate mitigation premium of 100.25 percent if applicable. Currently Utah revenue requirement on Rolled-In is less than Revised Protocol and is limited by the Rate Mitigation Cap.

128 In for two reasons. First, rates set in Docket No. 09-035-23 were based on Rolled-
129 In allocation plus the Rate Mitigation Cap so computing the incremental revenue
130 requirement in this filing using Rolled-In is consistent with the previous general
131 rate case as well as the subsequent major plant addition filing in Docket No. 10-
132 035-13. In addition, the Rolled-In methodology is not impacted by the Embedded
133 Cost Differential component of the Revised Protocol which is currently under
134 review by interested parties in Utah and the Company's other impacted
135 jurisdictions as I explain later in my testimony.

136 Second, the incremental electric plant in service included in this filing is
137 allocated on a system generation ("SG") factor, and the vast majority of the
138 remaining revenue requirement components are also allocated on either the SG
139 factor or the system energy ("SE") factor. Both of these factors are the same
140 under both the Revised Protocol and Rolled-In allocation methodologies, and the
141 incremental revenue requirement directly related to the two projects in this filing
142 is similar under either method. Exhibit RMP__(BSD-1) provides further
143 numerical details supporting the Utah-allocated revenue requirement of each
144 project.

145 **Q. Does the revenue increase requested in this filing include the additional one**
146 **percent related to the Rate Mitigation Cap?**

147 A. No. I have calculated the incremental revenue requirement using the Rolled-In
148 allocation with no adder related to the Rate Mitigation Cap. This approach results
149 in an appropriate level of incremental revenue requirement directly related to
150 these individual projects, and is also consistent with the approach taken in the

151 settlement of the Company's previous major plant filing in Docket No. 10-035-
152 13.

153 **Q. Is the Revised Protocol allocation method currently under review?**

154 A. Yes. The Revised Protocol agreement established a committee (the "Standing
155 Committee") for the purpose of continued monitoring and maintenance of the
156 Revised Protocol method. Representatives from the staff of the respective
157 Commissions that approved the Revised Protocol are members of the Standing
158 Committee and they work with the Company and other interested parties to
159 address issues that arise which may have an impact on the allocation
160 methodology. During 2009, the Company and the Standing Committee began
161 work to answer questions from interested commissioners regarding the continued
162 relevance of the Revised Protocol. Then, on November 9, 2009, the Utah
163 Commission issued an order in Docket No. 09-035-23 stating its intent that inter-
164 jurisdictional allocation issues be addressed and the reasonableness of any
165 allocation established prior to their approval of any future change in the
166 Company's rates. At the time of filing this application the Company continues to
167 work with the Standing Committee and other interested parties, including
168 participants from Utah, to determine a course of action related to the future of
169 inter-jurisdictional allocations.

170 **Q. Please describe Exhibit RMP__(BSD-1).**

171 A. Exhibit RMP__(BSD-1) contains the numerical details and calculations
172 supporting the revenue requirement of each project and the allocation to Utah.
173 Page 1.0 is a summary by project of the net incremental revenue requirement. The

174 first column on page 1.0 ties to the Utah Rolled-In results from Docket No. 09-
175 035-23. The next two columns show the impact of the settlement agreement
176 reached in the Company's first major plant addition case, followed by the
177 cumulative revenue requirement as a result of that case. The next two columns
178 show the incremental impact of the two major plant additions included in this
179 case, and the far right column contains the cumulative revenue requirement after
180 both major plant addition filings are layered onto the general rate case results.

181 Pages 2.0 through 2.5 contain the detailed numerical calculations for the
182 Populus to Ben Lomond transmission line, and pages 3.0 through 3.6 contain the
183 same details for the Dunlap I wind project. Pages 4.1 through 4.4 contain the
184 inter-jurisdictional allocation factors used to allocate revenue requirement
185 components to Utah.

186 **Q. What did the Company use for the “base case” mentioned above?**

187 A. The starting point in this case is the cumulative result of the Commission ordered
188 outcome in Docket No. 09-035-23 and the approved settlement of the first major
189 plant additions filing in Docket No. 10-035-13. This base scenario is needed as
190 the starting point from which to calculate the incremental impacts of the two
191 individual plant additions addressed in this filing.

192 **Q. How were the two major plant additions in this filing incorporated into the
193 “base case” results?**

194 A. Each project in this case was treated as an incremental adjustment to the “base
195 case” and entered into the JAM similar to adjustments in past Company filings.
196 Adjustment lead sheets and supporting calculations are provided on pages 2.0

197 through 2.5 and pages 3.0 through 3.6 of Exhibit RMP___(BSD-1). Each
198 adjustment includes the incremental change to rate base, depreciation expense,
199 operation and maintenance expenses (including any impact on system net power
200 costs), and other items such as property taxes, miscellaneous revenue, and income
201 taxes. Incremental rate base was computed using average balances, with electric
202 plant in service and accumulated depreciation reserve on a 13-month average.

203 **Q. Do your calculations include the impact on overall revenue requirement of**
204 **any changes in inter-jurisdictional allocation factors resulting from these**
205 **plant additions?**

206 A. Yes. Consistent with Filing Requirement C.5 of Utah Code Section 54-7-13.4,
207 allocation factors were allowed to remain dynamic in the JAM and were updated
208 to reflect the impact of each plant addition in the JAM. Load based allocation
209 factors, such as the SG and SE factors previously mentioned, are the same as
210 those used and approved in Docket No. 09-035-23. Page 4.4 of Exhibit
211 RMP___(BSD-1) details the change in allocation factors compared to the base
212 case.

213 **Q. Did you encounter any irregular results related to the dynamic allocation**
214 **factors?**

215 A. Yes. Because this filing includes updates to a limited set of revenue requirement
216 components, the Income Before Taxes (“IBT”) factor is disproportionately
217 impacted by the adjustments for the major plant additions. According to both the
218 Rolled-In and Revised Protocol allocation methods the IBT factor is used to
219 allocate state income taxes. In this case, if state taxes are left to be computed and

220 allocated in this manner the Utah-allocated revenue requirement impact of the
221 major plant additions would be higher than it otherwise should be.

222 **Q. What did you do to address this issue?**

223 A. For each major plant addition added in this case the IBT factor is allowed to
224 remain dynamic and allocate state income taxes computed within the JAM model;
225 however, each lead sheet also includes a line item adjustment to state income
226 taxes that results in the Utah-allocated state income taxes being included at the
227 Company's statutory rate of 4.54%. This rate is consistent with how the Company
228 computes tax related entries on its books and is the same method used to compute
229 the state taxes on revenue increases in general rate cases. The net result of the
230 adjustments to state income taxes for the two projects in this filing is a reduction
231 to Utah allocated revenue requirement of approximately \$1 million.

232 **Populus to Ben Lomond Transmission Line**

233 **Q. Please describe the various components comprising the revenue requirement**
234 **calculation for the Populus to Ben Lomond transmission line.**

235 A. The following data inputs (on a total Company basis) were used in calculating the
236 revenue requirement for the Populus to Ben Lomond transmission line segment
237 investment:

- 238 • Capital additions totaling \$548.1 million are scheduled to be placed in
239 service on or before November 16, 2010.
- 240 • Annual depreciation expense totaling \$10.9 million is included in
241 results by applying a transmission-specific composite depreciation rate
242 of 2.03 percent to projected net capital additions.

- 243 • Depreciation reserve totaling \$7.1 million is included on a 13-month
244 average basis consistent with net capital additions. An additional \$0.5
245 million of removal costs are included as an offset to depreciation
246 reserve.
- 247 • Incremental O&M expense is included in results totaling \$140,000.
248 These expenses represent incremental costs the Company will incur
249 during the first year of operation, including aerial safety patrols,
250 ground patrols, and minor corrections of conditions found.
- 251 • A reduction in net power costs totaling \$1.4 million is included based
252 on the additional transmission capacity of the Populus to Terminal
253 line. Please see the direct testimony of Dr. Hui Shu for a more detailed
254 discussion regarding net power costs.
- 255 • Incremental wheeling revenue of \$0.1 million is included based on the
256 ability of the line to provide additional short term wheeling for third
257 parties.
- 258 • Property tax expense totaling \$4.3 million is included in results by
259 taking into account the anticipated increase in assessed value and tax
260 expense for the 2011 assessment year. Property tax expense was
261 estimated by applying jurisdictional specific tax rates and assessment
262 ratios to each project's total capital costs.
- 263 • Tax entries to include the capital additions and the related book and
264 tax depreciation adjustments were calculated consistent with the
265 methodology used in Utah Docket No. 09-035-23. State income taxes

266 were adjusted such that the state income tax expense impact of the
267 incremental plant additions is at the statutory rate of 4.54%

268 **Dunlap I Wind Project**

269 **Q. Please describe the various components comprising the revenue requirement**
270 **calculation for the Dunlap I wind project investment.**

271 A. The following data inputs (on a total Company basis) were used to calculate the
272 revenue requirement for the Dunlap I wind project:

- 273 • Capital additions totaling \$264.5 million are scheduled to be placed in
274 service by September 30, 2010.
- 275 • Annual depreciation expense totaling \$10.3 million is included in
276 results by applying a composite depreciation rate of 4.06 percent to
277 projected wind capital additions and 2.03 percent to projected
278 transmission capital additions.
- 279 • Depreciation reserve totaling \$7.4 million is also included on a 13-
280 month average basis consistent with net capital additions.
- 281 • Incremental O&M expense totaling \$2.5 million is included in results
282 for the first year of operation. These expenses represent incremental
283 costs the Company will incur during the first year to operate the wind
284 project and newly installed transmission interconnection, including
285 materials, contracts, preventative maintenance, and other
286 miscellaneous operation and maintenance costs.
- 287 • A reduction in net power costs totaling \$8.0 million is included based
288 on the additional generating capacity of the plant. Please see the direct

289 testimony of Dr. Shu for a more detailed discussion regarding net
290 power costs.

291 • Incremental revenue totaling \$1.3 million from the sale of renewable
292 energy credits (“RECs”) is included based on the annual generation
293 output of the plant. This revenue is allocated to Utah consistent with
294 the methodology used in Docket No. 09-035-23. Please see the direct
295 testimony of Mr. Stefan Bird for further discussion related to REC
296 sales.

297 • Property tax expense totaling \$1.2 million is included in results by
298 taking into account the anticipated increase in assessed value and tax
299 expense for the 2011 assessment year. Property tax expense was
300 estimated by applying jurisdictional specific tax rates and assessment
301 ratios to each project’s total capital costs.

302 • Tax entries to include the capital additions and the related book and
303 tax depreciation adjustments were calculated consistent with the
304 methodology used in Utah Docket No. 09-035-23.

305 **Method of Cost Recovery**

306 **Q. Is the Company requesting approval to change retail rates as a result of this**
307 **application?**

308 A. Yes. The Company is requesting authority to adjust rates effective January 1,
309 2011, to begin to recover both the \$39.0 million for projects included in this case
310 as well as the \$30.8 million for projects included in the Company’s previous
311 major plant addition case, Docket No. 10-035-13. In addition, the Company

312 requests approval to begin collection of the amount deferred as a result of the
313 stipulation in Docket No. 10-035-13. As of December 31, 2010, this balance is
314 expected to be approximately \$15.7 million.

315 **Q. Please explain the Company's proposal to recover the balance of costs**
316 **previously deferred.**

317 A. As approved by the Commission in Docket No. 10-035-13 the Company began
318 deferring the incremental revenue requirement of the major plant items in that
319 case effective July 1, 2010. According to the stipulation in that docket, beginning
320 on the later of July 1, 2010, or the date that the projects are both in service², the
321 Company is to record a monthly entry of \$2,566,667 in a regulatory asset until
322 rates are adjusted to begin collecting the deferred balance from customers. The
323 deferred balance accrues a monthly carrying charge of 0.695 percent (8.34 percent
324 divided by twelve). By December 31, 2010, the accumulated balance in the
325 regulatory asset will be \$15,724,521 as shown in the following table.

Docket No. 10-035-13 Deferral

| | Monthly Carrying Charge | 0.695% | |
|--------|-------------------------|-----------|----------------|
| | Deferral | Interest | Ending Balance |
| Jul-10 | \$ 2,566,667 | \$ 8,919 | \$ 2,575,586 |
| Aug-10 | \$ 2,566,667 | \$ 26,819 | \$ 5,169,072 |
| Sep-10 | \$ 2,566,667 | \$ 44,844 | \$ 7,780,583 |
| Oct-10 | \$ 2,566,667 | \$ 62,994 | \$ 10,410,244 |
| Nov-10 | \$ 2,566,667 | \$ 81,270 | \$ 13,058,181 |
| Dec-10 | \$ 2,566,667 | \$ 99,674 | \$ 15,724,521 |

² The Dave Johnston Unit 3 pollution control equipment was placed into service May 27, 2010, and the various segments of the Ben Lomond to Terminal transmission line were all placed into service by April 2010.

326 The Company proposes to begin collecting the \$15.7 million plus ongoing
327 carrying charges from customers effective January 1, 2011, over an approximate
328 eight month period until the balance is collected. This treatment will closely align
329 the completion of the deferral recovery with the implementation of new rates in
330 the Company's next general rate case. Mr. Bill Griffith addresses the specifics of
331 the deferral recovery in his testimony. Currently the Company expects to file its
332 next general rate case by mid-January 2011 with new rates effective mid-
333 September 2011.

334 **Witnesses**

335 **Q. Please identify the other Company witnesses in this application and the**
336 **purpose of their direct testimony.**

337 A. The following Company personnel have provided direct testimony addressing
338 various issues in this application:

- 339 • Mr. John A. Cupparo, vice president of transmission for PacifiCorp,
340 provides an overview of the Populus to Ben Lomond transmission line and
341 demonstrates how the line is beneficial to customers.
- 342 • Mr. Darrell T. Gerrard, vice president of transmission system planning for
343 PacifiCorp, provides additional details and technical information on the
344 construction of the line.
- 345 • Mr. Stefan A. Bird, senior vice president of commercial and trading for
346 PacifiCorp Energy, provides information on the Dunlap I wind project.
- 347 • Mr. Bruce N. Williams, vice president and treasurer of PacifiCorp,
348 describes how the Company financed the construction of the major plant

349

additions.

350

- Dr. Hui Shu, manager of net power costs, presents the net power cost impact of the major plant additions.

351

352

- Mr. C. Craig Paice, regulatory consultant for cost of service, presents the class cost of service impacts related this filing and the Company's previous major plant addition case in Docket No. 10-035-13.

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- Mr. William R. Griffith, director of cost of service and pricing, provides the rate spread and rate design proposed to collect the incremental impact of both major plant addition cases and the tariff rider proposed to collect the deferred balance from Docket No. 10-035-13.

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

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A. Yes.