

Rocky Mountain Power  
Docket No. 10-035-124  
Witness: Dean S. Brockbank

BEFORE THE PUBLIC SERVICE COMMISSION  
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

---

Rebuttal Testimony of Dean S. Brockbank

Klamath

June 2011

1 **Q. Are you the same Dean S. Brockbank who submitted direct testimony in this**  
2 **proceeding?**

3 A. Yes.

#### 4 **Purpose and Overview of Rebuttal Testimony**

5 **Q. What is the purpose of your rebuttal testimony?**

6 A. My rebuttal testimony responds to issues raised regarding the Klamath  
7 Hydroelectric Settlement Agreement (“KHSA”) and to the arbitration decision  
8 related to the Hunter II environmental control investments.

#### 9 **Klamath Hydroelectric Settlement Agreement**

10 **Q. Please provide an overview of the areas covered in your rebuttal related to**  
11 **the KHSA.**

12 A. My rebuttal testimony responds to 1) the testimony of Office of Consumer  
13 Services (“OCS”) witness Ms. Michele Beck, recommending that the  
14 Commission deny Rocky Mountain Power’s request to recover any costs related  
15 to the KHSA and, 2) the testimony of UAE witness Mr. Kevin Higgins that  
16 customers should be afforded an offset for dam removal costs allocated to Utah  
17 and that it is premature to adjust the depreciation lives of the Klamath project  
18 assets given that up to \$250 million in funding from the State of California for  
19 dam removal has yet to be approved, and 3) the testimony of Division of Public  
20 Utilities (“DPU”) witness Dr. Artie Powell recommending that the depreciation  
21 lives of the Klamath Hydroelectric Project (“Project”) assets not be adjusted  
22 because the passage of federal legislation endorsing the KHSA is uncertain. In  
23 addition, my rebuttal testimony specifically explains that:

- 24 • PacifiCorp has not emphasized a dam removal outcome for the Klamath  
25 Hydroelectric Project to respond to regional interests;
- 26 • The KHSA benefits customers in all states served by PacifiCorp;  
27 PacifiCorp's customers in Oregon and California are funding costs for  
28 dam removal not in furtherance of their respective state policy preferences  
29 for dam removal but rather because the KHSA and the associated dam  
30 removal surcharges have been determined by the relevant state public  
31 utility commissions as being in the best interest of PacifiCorp's customers  
32 in those states; and
- 33 • A delay in an adjustment of the depreciation schedule for the Klamath  
34 facilities on the basis that California funding and federal legislation have  
35 yet to be enacted is unnecessary and may frustrate the realization of the  
36 KHSA and its customer benefits.

37 **Clarification of Relicensing and Settlement Efforts**

38 **Q. Do you agree with OCS witness Ms. Beck's contention (Beck/175-177) that**  
39 **PacifiCorp redirected its Project relicensing efforts toward a focus on dam**  
40 **removal shortly after filing its license application in 2004?**

41 A. No. Since the filing of the license application in 2004, PacifiCorp has pursued a  
42 joint track of engagement in settlement negotiations to resolve the relicensing  
43 process while also fully prosecuting the traditional relicensing application to  
44 obtain a new Project license. Had the Company pursued a dam removal focus, it  
45 would not have robustly engaged in the licensing process subsequent to filing the  
46 license application. PacifiCorp's pursuit of the licensing process since submittal

47 of the licensing application has been steadfast and will remain so until a new  
48 Project license is obtained or the facilities are removed consistent with the KHSA.  
49 Strong engagement in the relicensing process subsequent to submittal of the  
50 license application in 2004 is well documented in the Klamath Chronology  
51 included in my original testimony (Exhibit RMP\_\_\_DSB-2).

52 **Q. Can you provide some examples of efforts that contradict witness Ms. Beck’s**  
53 **contention that the last five to seven years of the 13-year relicensing process**  
54 **that the Company has pursued have been devoted to “satisfying the interests**  
55 **of Klamath River Basin regional entities whose goal was the removal of the**  
56 **dams rather than the relicensing of a generating facility”?** (Beck/222-224)

57 A. Yes. Since the submittal of the license application, PacifiCorp has vigorously  
58 pursued the relicensing process for the Project. These efforts have been  
59 contentious and strongly opposed by stakeholders interested in a dam removal  
60 outcome to the relicensing process. Some examples include the first ever  
61 challenge, in 2006, under the provisions of the Energy Policy Act of 2005, by a  
62 licensee to preliminary fishway prescriptions and terms and conditions issued by  
63 the U.S. Departments of Commerce and the Interior. This challenge resulted in a  
64 quasi-judicial hearing on issues of material fact underlying the agency fishway  
65 prescriptions and terms and conditions that are mandatory conditions that must be  
66 included in a new license issued by the Federal Energy Regulatory Commission  
67 (“FERC”).

68 Another example is PacifiCorp’s active participation and review of the  
69 Klamath River Total Maximum Daily Load (“TMDL”) water quality regulatory

70 process that would inform conditions imposed on the Project through the Clean  
71 Water Act 401 certification process. It is fair to say that PacifiCorp's efforts since  
72 the license application was filed, to ensure that the Project is fairly and  
73 appropriately assigned regulatory responsibilities have not been favorably viewed  
74 by stakeholders seeking a dam removal outcome outside of customer protections  
75 of the KHSA.

76 **KHSA was Executed as a Prudent Business Decision to Protect and Benefit**  
77 **Customers, Not to Advance State Policy Objectives**

78 **Q. Witness Ms. Beck contends that the KHSA resolves basin wide interests**  
79 **rather than issues germane to the continued operation of the Project and**  
80 **cites your testimony as a reason for this conclusion: "Mr. Brockbank**  
81 **describes settlement discussions in October 2004 with 'attention to resolving**  
82 **basin-wide issues among the stakeholders.' Brockbank Direct, line 288 –**  
83 **292." (Beck/183-185). Is this an accurate reading of your testimony?**

84 A. No. My testimony (Brockbank/288-292) explains that PacifiCorp began  
85 settlement discussions in October 2004 to resolve issues related to its relicensing  
86 application, and that those discussions continued through 2005 and mid-2006. At  
87 that point, in mid-2006, stakeholders participating in the relicensing settlement  
88 discussions turned their attention to resolving basin-wide issues among  
89 themselves and proceeded with those settlement discussions without PacifiCorp.  
90 Because these settlement discussions were of a different nature and not related  
91 directly to resolution of PacifiCorp's relicensing application and continued  
92 operation of the Project, PacifiCorp did not participate in these negotiations, as is

93 also stated in my direct testimony (Brockbank Direct/294-296). The end result of  
94 these stakeholder discussions of basin-wide issues was the Klamath Basin  
95 Restoration Agreement (KBRA). PacifiCorp is not a party to the KBRA as it deals  
96 with issues that are beyond the scope of PacifiCorp's relicensing application and  
97 does not address the continued operation of the Project.

98 **Q. Is there other support for your view that the KHSA is strictly related to**  
99 **resolution of the relicensing proceeding and continued operation of the**  
100 **Project?**

101 A. Yes. This view is also supported by the statement of purpose included in the  
102 KHSA:

103 "1.2 Purpose of Settlement  
104 The Parties have entered into this Settlement for the purpose of resolving  
105 among them the pending FERC relicensing proceeding by establishing a  
106 process for potential Facilities Removal and operation of the Project until  
107 that time."<sup>1</sup>

108 **Q. Witness Ms. Beck states as OCS's position that Utah customers should not**  
109 **bear KHSA-related costs because "the costs relate to resolving Klamath**  
110 **basin regional interests and not the continued operation of a generating**  
111 **resource". (Beck 205/206). Why do you believe witness Ms. Beck holds this**  
112 **view?**

113 A. I believe witness Ms. Beck is confusing the KBRA, which is an attempt to resolve  
114 basin-wide issues that are beyond the scope of Project relicensing and continued  
115 Project operations, with the KHSA, which does narrowly address the resolution of  
116 the relicensing process and the continued operation of the Project.

---

<sup>1</sup> KHSA §1.2, p. 3.

117 **Q. Even though PacifiCorp may not have signed the KBRA, do the Company’s**  
118 **KHSA implementation costs included in the case fund or implement activities**  
119 **under the KBRA?**

120 A. No. When negotiating the KHSA with many of the same stakeholders that had  
121 negotiated the KBRA, one of PacifiCorp’s key principles was that implementation  
122 activities under the KHSA were to address effects related solely to the Project and  
123 its continued operation and that PacifiCorp and its customers were not responsible  
124 for implementing KBRA-related basin wide restoration activities.

125 **Q. Is this principle included in the KHSA?**

126 A. Yes, this principle is included as a recital in the KHSA:

127                   “WHEREAS, PacifiCorp is a regulated utility and did not participate in  
128                   the KBRA negotiations and will not have obligations for implementation  
129                   of the KBRA”.<sup>2</sup>

130 **Q. Witness Ms. Beck states that under the KHSA the “expenditures and**  
131 **financial commitments by PacifiCorp, Oregon and California are intended to**  
132 **resolve long-standing and contentious disputes over resources in the Klamath**  
133 **River Basin, to the benefit of the interests of Indian tribes, environmental**  
134 **organizations, fishermen, water users and local communities.” (Beck/231-**  
135 **235). Do you agree that the KHSA is a one-sided agreement that benefits**  
136 **these regional interests at the expense of PacifiCorp or its customers?**

137 A. No. I believe the KHSA represents a fair and balanced resolution of the issues  
138 related to the relicensing and continued operation of the Project for the parties to  
139 the KHSA, including PacifiCorp and its customers in all the six states that  
140 comprise its service territory.

---

<sup>2</sup> KHSA §1.1, p. 3.

141 **Q. Please explain why you believe the KHSA benefits all of PacifiCorp's**  
142 **customers.**

143 A. Under the KHSA, customer costs related to dam removal are capped at \$200  
144 million and the Company and its customers are afforded liability protection  
145 against potential adverse consequences of dam removal. In addition, customers  
146 will continue to benefit from the low-cost power provided by the Project until the  
147 facilities are removed. The projected dam removal date of no earlier than 2020  
148 ensures that customers will benefit from the low-cost, carbon-free energy  
149 produced by the Project for at least ten years and the need to replace the energy  
150 from this generating resource is deferred for that 10-year period. The rebuttal  
151 testimony of Company witness Mr. Steven R. McDougal contains the details of  
152 the cost-benefit analysis conducted by the Company that demonstrates the KHSA  
153 is in the interest of the Company's customers.

154 **Q. UAE Witness Mr. Higgins recommends that Klamath dam removal costs**  
155 **allocated to Utah customers be offset in recognition that "customer**  
156 **contributions are being made in furtherance of Oregon and California state**  
157 **policies to remove this RMP system resource." (Higgins/348-349) Do you**  
158 **agree that these customer costs have been assessed based upon state policy**  
159 **preferences for dam removal in those states?**

160 A. No. It has been the policy preference of the Governors of both the State of  
161 California and the State of Oregon, and the resource agencies reporting to the  
162 Governors in those states. However, the customer surcharges in both California  
163 and Oregon were approved by the independent public utility commissions in those

164 states on the basis that the KHSA, including the imposition of customer  
165 surcharges, provides superior cost and risk protections for customers as compared  
166 to continuing on the path of relicensing the facilities. The Klamath allocation  
167 issues are addressed in the rebuttal testimony of witness Mr. McDougal.

168 **Q. Can you provide evidence that this was the basis of the decisions of the public**  
169 **utility commissions in California and Oregon?**

170 A. Yes. The recent order issued by the California Public Utilities Commission  
171 affirming dam removal surcharges for California customers supports this view  
172 through a finding of fact that “Through the use of the KHSA cost cap, ratepayers  
173 are protected from the uncertain costs of relicensing, litigation, and  
174 decommissioning that customers may be responsible for sans the KHSA. If the  
175 KHSA surcharge is not instituted, ratepayers would be exposed to an uncertain  
176 amount of costs.”<sup>3</sup> Similarly, the Oregon Public Utility Commission, in its review  
177 of surcharges for Oregon customers, found that “Because the KHSA limits costs  
178 and manages risk better than relicensing, we find the KHSA to be in the best  
179 interest of customers.”<sup>4</sup>

---

<sup>3</sup> CPUC Decision 11-05-002, May 6, 2011. Section 11, Paragraph 8.

<sup>4</sup> OPUC Order No. 10-364, p. 13.

180 **Appropriateness of Not Deferring Recovery of Relicensing and Settlement Costs**

181 **Q. Witness Ms. Beck apparently holds the view that the 13-year relicensing and**  
182 **settlement effort for the Project, and the associated costs, would be**  
183 **unnecessary but for the Company’s decision to enter into the KHSA.**  
184 **(Beck/218-221) Do you agree?**

185 A. No. The Company was obligated under the Federal Power Act to pursue  
186 relicensing of the Project unless it intended to surrender the Project license and  
187 decommission the facilities. As described in my direct testimony (Brockbank/346-  
188 349), PacifiCorp believes that decommissioning of the facilities is not in the best  
189 interests of the Company or its customers without necessary protections such as  
190 those afforded to the Company and its customers in the KHSA. Thus, the  
191 relicensing and settlement process costs were necessary to incur and are prudent  
192 and appropriate to include in rate base regardless of the Company’s decision to  
193 execute the KHSA to resolve matters related to the relicensing of the Project.

194 **Q. Do you then agree with the testimony of DPU witness Dr. Powell that “It**  
195 **appears that most, if not all, of these costs would be incurred regardless of**  
196 **which path the Company follows: relicensing or removal. Since these cost**  
197 **would be incurred regardless, and since the Dam is operational, I see no need**  
198 **to remove these costs from the case”?** (Powell/382-385)

199 A. Yes. The relicensing and settlement process costs have been prudently incurred  
200 consistent with the requirements of the relicensing process as overseen by the  
201 FERC and represent costs that will enter rate base regardless of whether Project  
202 dams are removed pursuant to the KHSA or the Project is ultimately relicensed.

203 As noted by witness Dr. Powell, removal of these costs from the case would not  
204 serve customer interests since this would result in substantial increases to overall  
205 project costs as additional AFUDC charges accumulate for the project. These  
206 costs would ultimately be borne by customers, thereby ultimately increasing  
207 customer costs.

208 **Reasonableness of Adjusting Depreciation Lives Now**

209 **Q. UAE witness Mr. Higgins cites the fact that the State of California has yet to**  
210 **enact funding for up to \$250 million in dam removal costs as a reason that it**  
211 **is premature to adjust the depreciation lives of the Klamath project assets.**  
212 **Do you view the lack of funding from the State of California at this time as**  
213 **an impediment to the KHSA moving forward?**

214 A. No. The KHSA identifies the customer contribution as the principal funding  
215 source for dam removal by specifying that any California bond funding (or other  
216 appropriate State of California funding mechanism) will be used to fund the  
217 difference between the customer contribution and the actual cost to complete dam  
218 removal.<sup>5</sup> Thus, the customer contribution through the surcharges on customers is  
219 the primary source for dam removal funding, with State of California funding  
220 necessary only if the actual cost of dam removal exceeds the customer  
221 contribution. The actual cost of dam removal has yet to be determined. The U.S.  
222 Department of the Interior, through the Secretarial Determination study process, is  
223 developing a detailed plan for removal of the facilities, which will include a  
224 detailed statement of the estimated costs of removal.<sup>6</sup> Until the detailed plan is

---

<sup>5</sup> KHSA §4.1.2.A, p. 24.

<sup>6</sup> KHSA §3.3.2, p. 19.

225 developed, the costs of dam removal remain uncertain and it is unclear if any  
226 funding from the State of California will be necessary.

227 **Q. What is the impact of delaying an adjustment to depreciation for the**  
228 **Klamath Hydroelectric Project?**

229 A. Delay in adjusting the depreciation schedule would conflict with the intent of the  
230 KHSA, which is to adjust the depreciation schedule of the facilities immediately  
231 to minimize the customer impact, i.e., to spread the costs out over as long of  
232 period as possible to reduce the impact to customers in a given time period.  
233 Otherwise, the impact to customers will be greater if full depreciation of the  
234 facilities occurs on a shorter timeframe. Therefore, I don't believe it is premature  
235 because deferring the depreciation adjustment to a future rate case following  
236 passage of legislation may have a greater impact to customers.

237 **Q. As the basis for a recommendation to remove accelerated depreciation of the**  
238 **Klamath project, DPU witness Dr. Powell cites uncertainty that**  
239 **Congressional approval of the KHSA will ultimately occur. As a rationale for**  
240 **this position, Witness Dr. Powell cites “the current economic and political**  
241 **climate” (Powell/365-366) given his understanding that “Congress must**  
242 **approve funds for removal costs”. (Powell/358) Do you agree with this**  
243 **assessment?**

244 A. No. The KHSA does not require that Congress allocate funding for dam removal.  
245 In fact, on this very point the KHSA states that “The United States shall not be  
246 liable or responsible for costs of Facilities Removal”.<sup>7</sup> Because the KHSA does  
247 not require that Congress authorize funding for dam removal, I believe the current

---

<sup>7</sup> KHSA §4.10, p. 31.

248 economic climate and challenging federal budget situation is not an impediment  
249 to Congressional authorization of the KHSA. Further, because federal funds for  
250 dam removal are not required, I believe this lessens potential political difficulties  
251 that could otherwise be present.

252 **Q. Are there other substantive reasons for not delaying the adjustment in the**  
253 **depreciation lives of the facilities?**

254 A. Yes, the KHSA was negotiated to protect PacifiCorp's customers in all of its  
255 states and adjustment of the depreciation schedule for the Klamath facilities at this  
256 time is consistent with the KHSA and the positions of the Oregon Public Utility  
257 Commission and the California Public Utilities Commission. Both of those state  
258 commissions have found the KHSA to be in the best interests of customers in  
259 those states. While the Company is optimistic that legislation endorsing the  
260 KHSA will be passed this year, obtaining this endorsement from Congress for the  
261 KHSA will, in part, be based upon the ability of the parties to the KHSA to  
262 demonstrate successful implementation of portions of the agreement and the  
263 support of entities outside the KHSA process that are in a position to determine  
264 the merits of the settlement. Because of the substantial customer benefits and  
265 protections included in the KHSA, I believe the Commission should adjust the  
266 depreciation schedule of the Klamath facilities in a manner consistent with the  
267 intent of the KHSA and thereby signal its support of the settlement to interested  
268 parties. The Commission's support of the KHSA in this manner would likely  
269 advance the process of obtaining federal legislation, thereby furthering the KHSA  
270 and the realization of its considerable customer cost and risk protections.

271 **Hunter II Arbitration**

272 **Q. Are you familiar with the arbitration between PacifiCorp and Deseret**  
273 **Generation & Transmission Cooperative that took place from January 31**  
274 **through February 8, 2011, and that Mr. Howard Gebhart discusses in his**  
275 **testimony?**

276 A. Yes.

277 **Q. What is the relationship between PacifiCorp and Deseret Generation &**  
278 **Transmission Cooperative, which we may refer to as simply “Deseret”?**

279 A. They are both co-owners of the Hunter Steam Electric Generating Unit No. 2,  
280 which is an electric generating facility in Castle Dale, Utah that is referred to as  
281 “Hunter II.” PacifiCorp is the majority owner of Hunter II with 60.310%, Deseret  
282 owns 25.108% and Utah Associated Power Systems (“UAMPS”) owns the  
283 remaining 14.582 %.

284 **Q. Are the rights and responsibilities of PacifiCorp and Deseret with respect to**  
285 **Hunter II governed by a contract?**

286 A. Yes, there is an *Ownership and Management Agreement Dated October 24, 1980*  
287 *between Utah Power & Light Company and Deseret Generation & Transmission*  
288 *Co-Operative (“O&M Agreement”). The O&M Agreement, including several*  
289 *amendments, spells out management and other contractual responsibilities*  
290 *between the owners of Hunter II.*

291 **Q. Are you familiar with the terms of that O&M Agreement and its**  
292 **amendments?**

293 A. Yes.

294 **Q. Which entity is responsible for the operation and management of the Hunter**  
295 **II facility under the O&M Agreement?**

296 A. Under the O&M Agreement, PacifiCorp is designated as the Operator of  
297 Hunter II. As the Operator of Hunter II, PacifiCorp has, subject to certain  
298 exceptions, the exclusive responsibility for the operation and management of  
299 Hunter 2 in accordance with “Reasonable Utility Practice,” as that term is defined  
300 in the O&M Agreement, and the other provisions of the O&M Agreement,  
301 including, but not limited to, responsibility for decisions with respect to the  
302 timing, extent and nature of any actions with respect to Capital Improvements in  
303 the ordinary course of business and the integration of the operation of Hunter II  
304 with the remainder of PacifiCorp’s electric utility system.

305 **Q. Have there been any amendments to the O&M Agreement that specifically**  
306 **address capital improvements?**

307 A. Yes. Prior to its amendment, Section 4.1(a) of the O&M Agreement required the  
308 unanimous consent of the Hunter II Management Council for certain enumerated  
309 capital improvements, such as capital improvements that were to be implemented  
310 within six months of being reported to the Management Council. In 1999,  
311 PacifiCorp and Deseret entered into a settlement that resolved a coal pricing  
312 dispute. As part of that settlement they entered into an *Agreement Regarding The*  
313 *Coal Supply And Pricing Relationship Between PacifiCorp And Deseret*  
314 *Generation & Transmission Co-Operative Under The Ownership And*  
315 *Management Agreement*, effective January 1, 1999 (hereafter “1999 Agreement”).  
316 Among other things, the 1999 Agreement replaced Section 4.1(a) of the O&M

317 Agreement with new language that provides a mechanism for Deseret to  
318 challenge and receive a determination, by binding arbitration and within 120 days,  
319 that Capital Improvements proposed by PacifiCorp requiring expenditures in  
320 excess of One Million Dollars (\$1,000,000) (“Major Capital Improvements”) are,  
321 or are not, consistent with Reasonable Utility Practice, as that term is defined by  
322 the O&M Agreement.

323 **Q. Briefly explain how decisions about Major Capital Improvements are**  
324 **handled under the O&M Agreement.**

325 A. Section 4.1(a) of the O&M Agreement, as amended by the 1999 Agreement,  
326 requires the unanimous consent of the Hunter II Management Council for all  
327 Major Capital Improvements, subject to arbitration procedures set out in Section  
328 4.1(a).

329 **Q. How does the arbitration procedure work?**

330 A. According to Section 4.1(a) of the O&M Agreement, as amended, each Major  
331 Capital Improvement proposed by PacifiCorp should be presented to the Hunter II  
332 Management Council and then voted on not less than 30 days later. If Deseret  
333 withholds its consent for a Major Capital Improvement, PacifiCorp and Deseret  
334 have 60 days to try and work things out. If they cannot, either may, within the  
335 next 60 days, submit the matter to arbitration before the American Arbitration  
336 Association.

337 **Q. And is that the provision under which the 2011 arbitration between**  
338 **PacifiCorp and Deseret arose?**

339 A. Yes.

340 **Q. Can you explain how the arbitration between PacifiCorp was initiated?**

341 A. Yes. In 2010, Deseret sued PacifiCorp in Utah state court, alleging various claims  
342 for breach of the O&M Agreement and other related causes of action. Among  
343 other things, Deseret claimed that it should not be required to pay for certain  
344 capital improvements including: (1) a “Scrubber Upgrade,” which increased the  
345 removal of SO<sub>2</sub> from the flue gas and included subsets of the project scope, which  
346 dealt with end-of-life issues for various pieces of equipment; and (2) a “Baghouse  
347 Conversion” which replaced a worn out electrostatic precipitator (“ESP”) with a  
348 pulse jet fabric filter or baghouse that controls particulate emissions at the plant.  
349 PacifiCorp removed the case to federal court and then moved the court for an  
350 order compelling arbitration on the issues of whether the Scrubber Upgrade and  
351 the Baghouse Conversion were consistent with “Reasonable Utility Practice.”  
352 The court granted PacifiCorp’s motion, compelling arbitration on this limited  
353 issue.

354 **Q. Did the parties then proceed to arbitrate those two issues?**

355 A. Yes, we went to arbitration for seven days between January 31-February 8, 2011,  
356 and a Final Award was issued on February 17, 2011.

357 **Q. What was the arbitrator’s job in the arbitration?**

358 A. By contract, “the sole question to be decided either “yes” or “no” by the arbitrator  
359 is whether the [disputed] Major Capital Improvement . . . is consistent with  
360 Reasonable Utility Practice, as defined by the O&M Agreement.”

361 **Q. What determination did the arbitrator make?**

362 A. He determined that the Baghouse Conversion is consistent with Reasonable  
363 Utility Practice, as defined by the O&M Agreement, but that the Scrubber  
364 Upgrade is not consistent with Reasonable Utility Practice.

365 **Q. Did the arbitrator explain his reasoning?**

366 A. Yes. Although by contract the arbitrator was only supposed to answer the sole  
367 question about Reasonable Utility Practice either “yes” or “no,” he chose to  
368 provide a written explanation along with these determinations. In this light, his  
369 written explanation was never intended to be comprehensive “findings of fact” or  
370 even a thorough discussion of all of the evidence presented because the  
371 arbitrator’s only job was to answer “yes” or “no” to the issue of Reasonable  
372 Utility Practice for the disputed projects.

373 **Q. Explain what the term “Reasonable Utility Practice” means.**

374 A. This term is defined in the O&M Agreement. It has a rather lengthy definition, but  
375 basically there are three components: First, a “Reasonable Utility Practice” is one  
376 that at a particular time is engaged in or approved by a significant portion of the  
377 electric utility industry; or, second, it is one that, based on the known facts, could  
378 have been expected to accomplish the desired result at the lowest reasonable cost  
379 consistent with good business practices, reliability, safety and expedition (while  
380 not being limited to the optimum practice, method or act); and third, a  
381 “Reasonable Utility Practice” is one that does not discriminate against Hunter II  
382 or Deseret’s ownership interest in Hunter II as compared to PacifiCorp’s practices  
383 at the other units at the Hunter plant or at its other plants.

384 **Q. Briefly explain what the arbitration award says with respect to the Baghouse**  
385 **Conversion.**

386 A. In explanation of his decision that the Baghouse Conversion is consistent with  
387 Reasonable Utility Practice, the arbitrator stated that the Baghouse Conversion (i)  
388 is a practice that is utilized by a significant portion of the electric utility industry;  
389 (ii) is the reliable, low-cost and perhaps only solution to end-of-life issues  
390 associated with the existing ESP given the need to also control mercury  
391 emissions; and (iii) does not discriminate against Deseret's interests.

392 **Q. Briefly explain what the arbitration award says with respect to the Scrubber**  
393 **Upgrade.**

394 A. In explanation of his decision that the Scrubber Upgrade is not consistent with  
395 Reasonable Utility Practice, the arbitrator concluded that: (i) no end-of-life issues  
396 are presented with regard to the Scrubber Project (page 15 of the award); (ii) the  
397 Scrubber at Hunter II is functioning well and meeting all emissions requirements  
398 (page 15 of the award); (iii) PacifiCorp made decisions relating to the Scrubber  
399 Upgrade without regard for its contractual obligations to Deseret (page 16 of the  
400 award); and (iv) PacifiCorp did not meet its burden of proof to show that the  
401 Scrubber Upgrade is consistent with Reasonable Utility Practice because (a)  
402 reliable evidence did not show that the Scrubber Upgrade was a practice that was  
403 approved by or engaged in by a significant portion of the electric utility industry  
404 when the existing scrubber was functioning well and meeting emission limits; (b)  
405 others in the electric utility industry would have postponed this upgrade as long as  
406 possible to see what regulatory limits would be imposed and what technology

407 would become available; (c) PacifiCorp did not consider alternatives to the  
408 Scrubber Upgrade; (d) the alleged benefit of the Scrubber Upgrade was minimal,  
409 as calculated by Mr. Gebhart, in light of the cost which far exceeded other  
410 PacifiCorp units for similar projects; (e) PacifiCorp voluntarily incurred the  
411 Scrubber Upgrade costs without arguing to the Utah Division of Air Quality that  
412 the costs outweighed any perceived benefits as PacifiCorp did for its Wyoming  
413 plants with the Wyoming Division of Air Quality, which demonstrated a lack of  
414 concern for PacifiCorp's contractual obligations to Deseret; and (f) PacifiCorp  
415 discriminated against Deseret's interest in Hunter II by applying similar scrubber  
416 upgrades to all Utah units when the facts did not fit and implementing the  
417 Scrubber Upgrade at Hunter II while not performing a similar upgrade at other  
418 facilities (pages 16 – 17 of the award).

419 **Q. Does the arbitrator's explanation rely on reasons that are not at issue in this**  
420 **rate case?**

421 A. Yes. As explained above, the Deseret arbitration award focuses solely on what the  
422 arbitrator considered to be the elements of the contractual obligation between two  
423 parties and the evidence that did or did not comply with those elements. Also, as  
424 explained below, those contractual obligations are different than the standard this  
425 Commission must employ in this rate case. For example, the arbitrator's  
426 conclusion that PacifiCorp did not meet its contractual obligation to consult with  
427 Deseret on the Scrubber Upgrade has no bearing on the issues before the  
428 Commission in this rate case. Likewise, whether PacifiCorp discriminated against  
429 Deseret in deciding to install the Scrubber Upgrade has no application to this rate

430 case. Yet, these were reasons that the arbitrator offered to explain why the  
431 Scrubber Upgrade is not consistent with Reasonable Utility Practice.

432 **Q. Does the arbitrator’s explanation erroneously rely on misconstrued evidence**  
433 **that is contrary to the evidence offered in this rate case?**

434 A. Yes. The arbitrator is simply wrong that the Scrubber Upgrade does not pose any  
435 end-of-life issues. The arbitrator focused on the modifications to the scrubber that  
436 are intended to meet a more stringent SO<sub>2</sub> emission rate, but are not the result of  
437 end-of-life issues, while virtually ignoring the more costly subset of end-of-life  
438 projects like the replacement of the dilapidated lime preparation area, which was  
439 also part of the Scrubber Upgrade. The testimony of Mr. Chad A. Teply makes  
440 clear that the Scrubber Upgrade includes costs for a subset of the project scope  
441 related to end-of-life issues for various pieces of equipment, such as reagent  
442 preparation equipment and scrubber waste handling equipment that simply does  
443 not fit the arbitrator’s rationale for his “No Reasonable Utility Practice”  
444 determination for the Scrubber Upgrade. Also, the arbitrator misconstrued the  
445 evidence related to the SO<sub>2</sub> reductions associated with the Scrubber Upgrade and  
446 improperly relied on Mr. Gebhart’s erroneous arbitration testimony in doing so,  
447 all as explained in Mr. Richard W. Sprott’s testimony filed in this rate case. In  
448 addition, the arbitrator demonstrated his misunderstanding of the regional haze  
449 requirements by asserting that PacifiCorp should have argued that the benefit did  
450 not justify the cost of the Scrubber Upgrade, as explained in Mr. Sprott’s  
451 testimony.

452 **Q. Did the arbitrator's explanation of his decision indicate the weight he gave to**  
453 **those reasons described above for concluding that the Scrubber Upgrade was**  
454 **not consistent with Reasonable Utility Practice?**

455 A. No. The arbitrator's explanation simply offered a list of reasons - some of which  
456 are contrary to the evidence in this rate case - without indicating which reason  
457 was more important or controlling than the others. For example, the arbitrator  
458 may very well have relied on his rationale that PacifiCorp discriminated against  
459 Deseret or failed in its contractual duties to Deseret more heavily than the other  
460 reasons he offered when reaching his ultimate decision that the Scrubber Upgrade  
461 was not consistent with Reasonable Utility Practice. Because that rationale has no  
462 bearing in this rate case, the ultimate conclusion of the arbitrator should likewise  
463 have no bearing.

464 **Q. Did the arbitrator consider the impact of the Scrubber Upgrade or Baghouse**  
465 **Conversion on the rates PacifiCorp charges in Utah?**

466 A. No. In the arbitration, the issues were very limited and focused solely on whether  
467 PacifiCorp's decision to install the Baghouse Conversion and Scrubber Upgrade  
468 at Hunter II is consistent with the contract requirement of Reasonable Utility  
469 Practice.

470 **Q. In your understanding, how was the issue presented to the arbitrator in the**  
471 **arbitration different from the issue presented to the Commission in this rate**  
472 **case?**

473 A. As I understand it, the Commission must examine the prudence of investments  
474 made by the Company to ensure that the Company's rates are just and reasonable

475 for the retail customers in Utah and that the Company's investors are fairly  
476 compensated. This typically requires the Commission to consider both long-term  
477 and short-term consequences to customers as well as the reasonableness of the  
478 Company's actions in relation to its entire system. The arbitrator did not examine  
479 these issues. He was limited to looking at whether PacifiCorp fulfilled its  
480 contractual obligations to a single joint owner, Deseret. He was not authorized to  
481 consider impacts upon customers, and did not consider all of the Company's  
482 system, just one generating unit in isolation. This latter factor is extremely  
483 important. If an owner has to make environmental upgrades at only one  
484 generating unit, the owner may be able to delay the upgrade to the last date  
485 feasible. That is how the arbitrator appears to have viewed the Company's  
486 actions. But, of course, the Company has 26 coal units to manage and, as the  
487 testimonies of other Company witnesses in this case have repeatedly emphasized,  
488 it is simply not feasible or economic to delay environmental upgrades for all 26  
489 units to the last moment. Thus, the Commission's assessment of the Company's  
490 action should focus on the system, not an individual unit.

491 **Q. Mr. Gebhart implies that the arbitrator adopted Mr. Gebhart's conclusions**  
492 **in the arbitration. Is that accurate?**

493 A. No. As explained above, the arbitrator made no actual factual "findings" at all  
494 about Mr. Gebhart's conclusions or otherwise. Rather, he simply was called upon  
495 pursuant to the terms of the parties' arbitration agreement to answer a "yes" or  
496 "no" question about whether the Company had carried its burden to prove specific  
497 investments were "Reasonable Utility Practices" as defined in the parties'

498 commercial contract. In the arbitrator's explanation, he did make reference to  
499 some of the arbitration testimony offered by Mr. Gebhart, but as explained above  
500 in reference to the testimony of Mr. Teply and Mr. Sprott, the arbitrator did so in  
501 error. In any event, because the arbitration decision is limited to a "yes" or "no"  
502 award, it is at best misleading to say that the arbitrator adopted any witnesses'  
503 conclusions, and it is certainly a misstatement to say the arbitrator considered the  
504 same issue that is now before this Commission.

505 **Q. Does this conclude your rebuttal testimony?**

506 **A. Yes.**