

1 **Q. Please state your name.**

2 A. My name is Gregory N. Duvall.

3 **Q. Have you previously filed testimony in this case?**

4 A. Yes. I filed direct testimony in this case.

5 **Q. Please describe the structure of your rebuttal testimony.**

6 A. My rebuttal testimony is comprised of three sections:

- 7 • Section I – Net Power Costs;
- 8 • Section II – Apex; and
- 9 • Section III – Hedging.

10 **Section I – Net Power Costs**

11 **Q. What is the purpose of your rebuttal testimony on net power costs?**

12 A. I will respond to the adjustments to the Company’s Net Power Costs (“NPC”) presented by Mr. George Evans on behalf of the Utah Division of Public Utilities (“DPU”), Mr. Randall Falkenberg and Ms. Donna Ramas on behalf of the Utah Office of Consumer Services (“OCS”), and Mr. Mark Widmer on behalf of the Utah Industrial Energy Consumers (“UIEC”).

17 **Q. Please explain how your testimony in Section I is organized.**

18 A. First, I present the Company’s rebuttal recommendation for NPC in this case and explain why it is reasonable on an overall basis. The rebuttal NPC reflects corrections and updates designed to increase the accuracy of NPC. My testimony explains why the Commission should allow such an update to NPC in this and future filings. The rebuttal NPC also reflects certain adjustments accepted by the Company.

24 Second, I discuss how the Company’s rebuttal NPC compares with recent
25 NPC benchmarks.

26 Third, I respond to the specific adjustments that the Company opposes.

27 **Q. Are there any NPC adjustments sponsored by Messrs. Evans, Widmer, or**
28 **Kevin Higgins that are addressed in the testimony of other Company**
29 **witnesses?**

30 A. Yes. Company witnesses Mr. Stefan A. Bird and Mr. John A. Apperson join me
31 in responding to the hedging adjustments presented by Messrs. Evans, Widmer,
32 and Higgins. Mr. Frank C. Graves from The Brattle Group also provides
33 testimony on these issues. Company witness Ms. Cindy A. Crane addresses Mr.
34 Falkenberg’s and Mr. Widmer’s Bridger assessments and citations and fuel
35 quality adjustments and Mr. Widmer’s adjustment to correct the fuel prices for
36 Jim Bridger and Huntington. Modifications to the Company’s requested price
37 increase as a result of adjustments to NPC are reflected in the rebuttal testimony
38 and exhibits of Mr. Steven R. McDougal.

39 **NPC Recommendation**

40 **Q. What is your NPC recommendation in this case?**

41 A. Based upon corrections, updates, and accepted adjustments, my rebuttal testimony
42 supports total-Company NPC of \$1.508 billion, which is \$644.1 million on a
43 Utah-allocated basis. This is the equivalent of \$24.48 per megawatt-hour
44 (“/MWh”). The results of the Company’s rebuttal NPC study are provided in
45 Exhibit RMP____(GND-1R).

46 **Q. Please describe Exhibit RMP__(GND-2R).**

47 A. Exhibit RMP__(GND-2R) summarizes the NPC impact of the corrections,
48 updates, and accepted adjustments.

49 **Q. Please describe briefly the corrections that the Company has included in the**
50 **rebuttal NPC.**

51 A. The corrections include the following, some of which were proposed by OCS and
52 UIEC:

- 53 • Capacity changes related to several capital addition projects as identified
54 in the Company's response to Filing Requirement R746-700-23-C.8.h, and
55 proposed by both OCS and UIEC as Adjustment 20 and Adjustment 7,
56 respectively.
- 57 • BPA Network integration transmission service expenses, which is also
58 proposed by OCS as part of OCA Adjustment 12 and by UIEC as UIEC
59 Adjustment 16.
- 60 • Roseburg Forest Products contract energy, which is also proposed by OCS
61 as part of OCS Adjustment 6 and by UIEC as UIEC Adjustment 18.
- 62 • Hunter plant station services exclusion of the non-ownership share of the
63 plant, which is part of OCS Adjustment 16.
- 64 • Pricing of Douglas PUD settlement, which was incorrectly stated.
- 65 • Foote Creek wind profile, which did not reflect the leap year correctly.
- 66 • Chehalis pipeline expenses, which did not reflect the leap year correctly.
- 67 • Grant Reasonable revenue, which did not reflect the correct share of the
68 project output.

69 These corrections reduce NPC by approximately \$1.0 million on a total Company
70 basis.

71 **Q. Does the Company's rebuttal NPC also reflect updates to NPC?**

72 A. Yes. To increase the accuracy of the Company's NPC forecast, in addition to
73 making the corrections listed above, the Company updated the official forward
74 price curve ("OFPC") to the March 31, 2011 curve, updated existing contracts to
75 reflect any new information, and included contracts that the Company entered into
76 since I filed my direct testimony. Overall, these updates decrease total Company
77 NPC by \$9.4 million.

78 **Q. Please describe briefly the contract updates.**

79 A. The updates to existing contracts include the following, some of which were
80 proposed by OCS and UIEC:

- 81 • Moving 48-month historical period for hydro outage from the one ended
82 to December 2009 to the one ended June 2010, which is also proposed by
83 UIEC as UIEC Adjustment 10.
- 84 • Chelan County budget for the Company's purchase expenses of Mid C
85 generation from the Chelan County, Washington.
- 86 • Douglas County budget for the Company's purchase expenses of Mid C
87 generation from the Douglas County, Washington.
- 88 • PGE Cove purchase expenses to reflect the latest projection by Portland
89 General Electric Company.
- 90 • Black Hills sales capacity and energy prices.

- 91 • APS point-to-point transmission expense to reflect the tariff rates that will
92 be in effect during the test period.
- 93 • Idaho Power Company’s point-to-point transmission expense to reflect the
94 tariff rate that will be in effect in the test period.
- 95 • Coal costs to reflect updates, and corrections that were proposed as OCS
96 Adjustment 19 and UIEC Adjustments 11 and 12 that are addressed by
97 Ms. Crane.

98 These contract updates decrease NPC by approximately \$11.3 million on a total
99 Company basis.

100 **Q. Please briefly describe the new information that is included in the**
101 **Company’s rebuttal NPC.**

102 A. The new information since the Company’s direct filing includes the following,
103 some of which were proposed by UIEC:

- 104 • NV Energy sales, which is also proposed by UIEC as UIEC Adjustment
105 15.
- 106 • Threemile Canyon QF contract extension, which is also proposed by
107 UIEC as UIEC Adjustment 19.
- 108 • Monsanto interruptible contract pricing, which was authorized by the
109 Idaho Public Utilities Commission in the Company’s last general rate case
110 and also proposed by UIEC as UIEC Adjustment 20.
- 111 • Extension of the Clay Basin gas storage contract.
- 112 • Small QFs to reflect new contracts that the Company has entered into
113 since the direct filing.

- 114 • Jolly Hills, which is a non-owned generator in the Company's east
115 balancing authority area that the Company is required to provide ancillary
116 services.
- 117 • Biomass non-gen agreement.
- 118 • Removing generation from the Condit facility to reflect the decision to
119 decommission the Condit Dam in November 2011, given that the
120 Company's has received all necessary licenses and permits and has
121 entered into contract with JR Merit to perform the dam removal.

122 These updates increase NPC by approximately \$1.9 million on a total Company
123 basis.

124 **Q. How did the Company update the OFPC in the rebuttal filing?**

125 A. The Company updated the OFPC from the November 8, 2010 OFPC that was
126 used in the Company's direct filing to the March 31, 2011 OFPC.

127 **Q. Please describe the OFPC and what is involved in updating to a new OFPC.**

128 A. The OFPC reflects the forward market prices for power and natural gas, which the
129 Company uses both for general business purposes and for regulatory filings.
130 These prices are developed by the Company's power and gas traders based on
131 their interaction with other parties in the wholesale markets. At each quarter end,
132 the Company's risk management group independently verifies the market prices
133 by obtaining broker quotes for the various electric and natural gas products at
134 each market hub. The traders' forward price curve must be within five percent of
135 the broker quotes independently acquired by the risk management group. If the
136 difference is greater than five percent for any one market, then an adjustment is

137 made to the traders' curve to bring it into tolerance with the broker quotes. Once
138 complete, the quarter end curve is deemed to be the OFPC. No models are used to
139 develop the OFPC.

140 In addition to updating the market prices, an extract of the Company's
141 records is made to capture all new physical short-term firm electric and natural
142 gas sales and purchases along with swaps that were entered into after the
143 Company locked down the NPC study included in its direct filing. Hydro is also
144 reshaped to the new OFPC, and other contracts that have market indexed pricing
145 are updated.

146 **Q. Is the OFPC used in this case formulated and applied in the same manner as**
147 **in past Utah general rate case ("GRC") filings?**

148 A. Yes. The Company has used the same basic approach to formulating and applying
149 its OFPC for many years.

150 **Q. How does the update to the OFPC affect the hedging costs reflected in NPC?**

151 A. The update changes to the mark-to-market valuation of the Company's hedging
152 instruments for the test period, reducing the costs reflected in the case from \$91
153 million to \$82 million on a total Company basis.

154 **Q. Do other commissions allow the Company to update its OFPC after the**
155 **initial filing?**

156 A. Yes. This has become the regular practice in several of the Company's other
157 jurisdictions with the goal of improving the accuracy of the NPC in rates. For
158 example, Oregon allows the Company to update its OFPC after it has entered its
159 final order but prior to the time rates go into effect.

160 **Q. What is the Commission’s general policy on the Company updating NPC in**
161 **its rebuttal testimony?**

162 A. In the order in the Company’s 2009 Utah general rate case, Docket 09-035-23,
163 (“2009 GRC”), the Commission decided that it would “continue to apply a case
164 by case approach for considering what are referred to as updates or corrections,
165 and consider arguments as to what constitutes the best available information for
166 use in a future test period.”¹

167 **Q. Why should the Commission allow the Company’s proposed NPC updates in**
168 **this case?**

169 A. Consistent with the Commission’s desire to include the best available information
170 for use in a future test period, the updates will present a more accurate reflection
171 of the level of NPC that is expected to occur in the test period. Moreover, the
172 Company’s update is limited to updates to the OFPC and specific contracts, many
173 of which were proposed by other parties. These updates are transparent, can be
174 easily verified, are not biased in only one direction and are straightforward to
175 model in GRID. The Company also provides work papers to support these
176 updates. For these reasons, evaluating the Company’s update at the rebuttal stage
177 does not unduly burden other parties.

178 **Q. Is the Company concerned with a mismatch if the Commission allows the**
179 **updated contracts, but does not allow the Company to update its OFPC?**

180 A. Yes. As I explained above, the update to the OFPC updates all new physical
181 short-term firm electric and natural gas sales and purchases. If the Commission

¹ *Re Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah*, Docket 09-035-23, Report and Order at 59 (Feb. 18, 2010).

182 allows the contract updates identified by the Company but does not allow an
183 update to the OFPC, the Commission will in effect be allowing an update to a
184 subset of contracts only.

185 **Q. Do you have any further comments on the Company's NPC update**
186 **proposal?**

187 A. Yes. In this case, the Company's update decreases NPC. The Company proposes
188 that if the Commission accepts the Company's update in this case, it establish a
189 clear and consistent policy allowing updates of the same elements of NPC in
190 future cases, whether the updates increase or decrease NPC. If the Commission
191 rejects updates, then NPC should be restated at the higher, previous level in the
192 Company's direct case, adjusted for corrections and the specific intervenor
193 adjustments adopted by the Company.

194 **Q. Has the Company accepted any adjustments proposed by other parties?**

195 A. Yes, the Company has adopted two adjustments that are proposed by parties. The
196 first is to extend four QF contracts that are located in Utah as proposed by DPU.
197 The Company currently does not have contracts through the end of the test period
198 with these QFs. However, given the pricing of the QF contracts, the impact on
199 NPC is expected to be minimal. The second is to adopt OCS Adjustment 7 and
200 UIEC Adjustment 14 to model Bear River median generation to include flood
201 control years and to increase the reserve capability of the Bear River projects.
202 Adopting these adjustments reduces NPC by approximately \$2.8 million on a total
203 Company basis.

204 **General Response to NPC Adjustments**

205 **Q. How have the Company's NPC included in rates compared with actual NPC**
206 **in recent years?**

207 A. NPC in rates have consistently been below actual NPC in recent years.

208 **Q. Did the Commission's recent order approving an Energy Balancing Account**
209 **("EBA") for the Company address this issue?**

210 A. Yes. The Commission explained that "the increasing magnitude of the difference
211 between system forecast and actual net power cost and the underlying variability
212 of these costs raise a concern regarding the Company's financial health and fair
213 rates to customers going forward."² The Commission concluded that it had an
214 opportunity to address this concern through adoption of the EBA.

215 **Q. Is the Company concerned that the NPC adjustments proposed by parties in**
216 **this filing could undermine the Commission's objective in adopting the EBA?**

217 A. Yes. While the Commission expressly adopted the EBA to address the growing
218 disparity between forecast and actual NPC, the volume and magnitude of the NPC
219 adjustments in this case threaten to increase that disparity and work at cross-
220 purposes with the EBA. The parties in this case proposed a total of approximately
221 70 NPC adjustments in this case with some overlap (the DPU proposed 12, OCS
222 proposed 38 (combined into 23), and UIEC proposed 21).

²*Re Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism*, Docket 09-035-15, Corrected Report and Order at 66 (March 3, 2011).

223 **Q. Why do you believe that the number of NPC adjustments (~70) in this case is**
224 **excessive?**

225 A. The Company has used the GRID model to determine NPC in Utah GRCs and
226 other proceedings related to NPC since 2001. Through these filings, working with
227 multiple stakeholders in several states, the Company has refined the GRID model
228 and its inputs every year to become a more accurate forecasting tool that better
229 represents the actual operations of the system. Additionally, the Company's initial
230 NPC filing in this case adopted a number of adjustments that parties proposed in
231 previous Utah filings, which the Company hoped would diminish the number of
232 adjustments in this case. Despite these efforts, the number and size of the
233 adjustments has, if anything increased from recent proceedings.

234 **Q. Do you have any general comments on the type of adjustments proposed by**
235 **the parties?**

236 A. Yes. At this point, it is apparent that it has become more difficult for parties to
237 propose legitimate adjustments to the GRID model and its inputs that improve the
238 accuracy of the forecasted test year NPC. Instead, many adjustments appear to
239 have been proposed with the sole goal of lowering NPC, with no justification for
240 why the party believes that actual NPC will be lower in the test period given that
241 history has shown the opposite. Some examples of these types of adjustments are
242 changing from a five-year average to a three-year average for system losses due to
243 the fact that in the current year a three-year average is lower than a five year
244 average, or, judging a contract to not be used and useful in the current year, when
245 its use has not changed from previous years.

246 **Q. Are these adjustments out-of-step with the direction from the Commission in**
247 **its Order on Test Period?**

248 A. Yes. In the Order on Test Period, dated March 30, 2011, the Commission placed
249 all parties on notice that as it considered “evidence supporting forecasts in this
250 proceeding, especially deviations from historical trends, [the Commission] will
251 give substantial weight to data reflecting actual, verifiable experience.” With
252 respect to NPC, the Company’s actual, verifiable experience is that: (1) NPC are
253 increasing, consistent with historical trends; (2) the GRID model reasonably
254 captures those increases for normalized ratemaking if, as in this case, the
255 Company is permitted to use a forward test period which generally aligns with the
256 rate-effective period; and (3) NPC modeling adjustments such as those proposed
257 in this case which significantly decrease the GRID results reduce the overall
258 accuracy of the NPC forecast.

259 **Q. Are there any benchmarks relevant to the evaluation of the Company’s**
260 **proposed NPC for the test year?**

261 A. Yes. On March 17, 2011, I filed testimony in support of the Company’s 2012
262 Transition Adjustment Mechanism before the Oregon Public Utility Commission.
263 The rate effective period and test period for that case are the 2012 calendar year,
264 or six months further out than the test period in this case. The NPC forecast in that
265 case was \$1.558 billion on a total Company basis, or approximately \$37 million
266 higher than the forecast presented in the Company’s direct testimony in this
267 docket.

268 **Q. What does this benchmark indicate?**

269 A. Consistent with historical trends and the Company's actual, verifiable experience,
270 NPC are continuing to increase and are forecast to be higher in the 2012 rate
271 effective period than the forecast for the test period. This benchmark confirms the
272 overall reasonableness of the Company's NPC forecast in this case.

273 **Summary of Company Responses to NPC Adjustments**

274 **Q. Given the number of NPC adjustments proposed in this case, have you**
275 **prepared a summary of the Company's responses to these adjustments?**

276 A. Yes. The summary is set forth below.

277 **Wind Integration Adjustments**

278 **Wind Study Modeling (OCS Adjustment 1, DPU Adjustment 4)**

279 Mr. Falkenberg and Mr. Evans suggest that the Company's modeled reserves for
280 wind are too high and not reflective of actual operations. I provide a detailed
281 response to OCS's points, demonstrating the robustness of the 2010 Wind
282 Integration Study ("Wind Study"), and provide a comparison to actual reserves
283 held by the Company in 2010 that shows the Company's Wind Study results
284 understate the actual reserves required to manage the volatile and unpredictable
285 nature of load and wind. The wind integration cost in this filing equates to
286 \$6.49/MWh, which is slightly lower than the wind integration costs of
287 \$6.62/MWh approved by the Commission in the Company's 2009 GRC.

288 **Gadsby CT Usage (DPU Adjustment 2, OCS Adjustment 2, and UIEC**
289 **Adjustment 3)**

290 In the Wind Study, the Company compared its modeling of Gadsby Units 4-6
291 with actual operations and concluded it was consistent with actual operations.³
292 This must run setting is applied in GRID to circumvent the fact that GRID
293 establishes unit commitment on price and not necessarily on operating reserve
294 requirements. Using the must-run assumption, Gadsby CTs ran at a 35 percent
295 capacity factor which exactly matched actual operations.

296 **Combined Cycle Must Run (OCS Adjustment 2)**

297 In the Wind Study, the Company compared its modeling of Current Creek with
298 actual operations and concluded it was consistent with actual operations. Using
299 the must-run assumption, Currant Creek ran at a 63 percent capacity which was
300 very close to its actual capacity factor of 65 percent.

301 **Wind Contingency Reserves (DPU Adjustment 3 and OCS Adjustment 1)**

302 OCS's and DPU's adjustment is nonsensical, in that it violates WECC Standard
303 BAL-STD-002-0 under which the Company is required to carry operating
304 reserves. The Company cannot use operating reserves to satisfy the additional
305 reserves required to follow the variations of load and wind generation.

306 **Spinning Reserve Increase (DPU Adjustment 4)**

307 Using actual operating reserve data, the Company demonstrates the
308 reasonableness of the Company's modeling of wind integration in the current
309 filing. Mr. Evans only accounts for 10-minute reserves in his analysis of the

³ Docket No. 11-2035-01, PacifiCorp 2011 IRP, Appendix I at 207 (March 31, 2011).

310 Company's modeling of wind integration and fails to include the necessary load
311 following reserves the Company must use to balance the variations in its portfolio
312 of resources and load over a sixty minute time period.

313 **Non-Owned Wind Facilities (DPU Adjustment 5)**

314 Federal law requires the Company to provide ancillary services to wholesale
315 customers under its Open Access Transmission Tariff ("OATT"), which does not
316 allow the Company to charge separately for wind integration service. Moreover,
317 customers benefit from the Company being a balancing authority and the
318 revenues associated with wheeling for wholesale customers. Until the Federal
319 Energy Regulatory Commission ("FERC") allows the Company to recover such
320 charges from wholesale customers, these costs should continue to be recovered in
321 rates.

322 **Market Caps Adjustment (DPU Adjustment 6, OCS Adjustment 18, and**
323 **UIEC Adjustment 17)**

324 As explained in my direct testimony, the Company's current modeling of market
325 caps is a more accurate and comprehensive approach to modeling market depth.
326 What DPU does not recognize in its testimony, but does show in its actual coal
327 generation chart, is that the Company's proposed market caps (1) allow the GRID
328 model to reflect more coal generation on a net basis than the old market caps, and
329 (2) that GRID models more than actual coal generation. OCS and UIEC recognize
330 that coal generation is no longer the point of contention, and instead have changed
331 their argument to simply say that there is supposed liquidity in these markets,
332 even though the Company's historical four-year average of STF transactions does

333 not support this conclusion. The Commission rejected this adjustment in the 2009
334 GRC and the parties have provided no basis for reconsideration of this decision.

335 **Trading and Arbitrage Adjustment (DPU Adjustment 9 and OCS**
336 **Adjustment 5)**

337 GRID already includes arbitrage margins. DPU's and OCS's adjustments double
338 counts the benefits already included in GRID.

339 **Wheeling Adjustments**

340 **Cal ISO Wheeling and Service Fees (DPU Adjustment 7, OCS Adjustment**
341 **10, and UIEC Adjustment 1)**

342 Cal ISO fees are costs of doing business and are recurring expenses incurred by
343 the Company. Elimination of these fees is unjustified and would incent the
344 Company to discontinue doing business with the Cal ISO and incur higher costs.

345 **DC Intertie (OCS Adjustment 10 and UIEC Adjustment 8)**

346 The DC Intertie wheeling contract was entered into in 1994 and has been included
347 in NPC for 17 years. OCS and UIEC argue that it is not used and useful, even
348 though its use has not changed for several years. The Company has used and
349 continues to use the DC Intertie wheeling contract to import power from the
350 Nevada Oregon Border ("NOB") market to serve load.

351 **Centralia Point-to-Point (OCS Adjustment 10 and UIEC Adjustment 9)**

352 This contract was prudently executed to serve load. The five-year term of the
353 contract was the least cost, least risk alternative available at the time it was
354 entered into. It is inappropriate to disallow the contract now in the final years of

355 the contract, based upon changed facts and circumstances, when the Company
356 acted prudently in executing and managing the contract.

357 **BPA/Idaho Power Rate Increase (OCS Adjustment 12)**

358 The currently filed Idaho Power wheeling rate of \$1,633.30/MW-month is an
359 existing charge the Company is incurring today.⁴

360 The rate increases by BPA related to transmission rates or wind integration
361 charges meet the Commission's known and measurable standard and are
362 straightforward and transparent. These contract updates are similar to the BPA
363 Peaking and Grant County contract updates allowed in the 2009 GRC.

364 **Transmission Imbalance Normalization (OCS Adjustment 12)**

365 This adjustment involves the treatment of imbalance charges. Mr. Falkenberg
366 incorrectly conflates imbalance charges paid by the Company to third parties with
367 imbalance charges received by the Company from third parties. Imbalance
368 charges paid by the Company are real expenses of doing business, while
369 imbalance charges received by the Company are required to be returned to
370 wholesale wheeling customers pursuant to FERC Order 890. OCS's adjustment
371 treating the payment and receipt of imbalance charges in the same manner is
372 incorrect.

373 **Contract Adjustments**

374 **Morgan Stanley Call Options (DPU Adjustment 8 and UIEC Adjustment 4)**

375 These contracts were part of the Company's strategy to rely on Front Office
376 Transactions as identified in the 2004 Integrated Resource Plan ("IRP") and the

⁴ See www.oatiosis.com/IPCO/IPCOdocs/Transmission_Rates_09-30-10.pdf.

377 2004 IRP Update. Relying on Front Office Transactions saved customers \$639
378 million. DPU's and UIEC's contention that these contracts did not provide a
379 benefit to customers is unfounded and is based upon hindsight, instead of the
380 circumstances at the time of execution as documented on page 172 of the
381 Company's 2004 IRP.⁵

382 **Black Hills and UMPA II Shaping (OCS Adjustment 4 and UIEC**
383 **Adjustment 6)**

384 OCS's and UIEC's recommendations should be rejected because it is
385 unreasonable to use actual historical information for sales contracts while using
386 GRID optimized results for purchased power contracts. While the Commission
387 has allowed this treatment for the SMUD contract based on the specific
388 circumstances of that contract and a specific settlement agreement related to it, a
389 generalization to other contracts is not reasonable and does not support the
390 treatment of these contracts in the past when the Commission decided on the
391 unique treatment of the SMUD contract.

392 **Evergreen Contract (OCS Adjustment 6)**

393 OCS's adjustment is inconsistent with the Company's standard modeling of new
394 resources. Mr. Falkenberg has supported this modeling in other jurisdictions.

395 **APS Daily Screening Adjustment (OCS Adjustment 6)**

396 The Company applied daily screens to the APS Supplemental contract to conform
397 to the screening approved by the Commission in the past to screen call option
398 contracts. OCS provides no evidence why this approach should change.

⁵The Company's 2004 IRP can be found on the Company's website at the following address:
http://www.pacificorp.com/content/dam/pacificorp/doc/Environment/Environmental_Concerns/Integrated_Resource_Planning_14.pdf.

399 **Transmission Adjustments**

400 **Short-Term Firm Transmission (UIEC Adjustment 5)**

401 UIEC's proposal adds complexity without increasing accuracy. The approach the
402 Company now uses is one that was sponsored by Mr. Widmer when he was a
403 witness for the Company, and he has presented no substantive basis for the
404 change in approach.

405 **Non-Firm (NF) Transmission (OCS Adjustment 11)**

406 As discussed in my direct testimony, the Company purchases and uses NF
407 transmission in the same way as short-term firm ("STF") transmission. The
408 Company will describe the reasons it enters into NF transmission and the fact that
409 GRID cannot accurately capture or model all NF transmission costs on a
410 volumetric basis. The Commission should reject OCS's adjustment because the
411 Company's modeling of NF transmission is the most accurate reflection of the
412 costs and benefits associated with the service.

413 **Transmission Loss Adjustment (OCS Adjustment 13)**

414 The underlying assumption of OCS's adjustment—that line losses are on a
415 consistent downward trend—is faulty. I show that the losses in this case are
416 reasonable when looking at all of the most recent Company data on line losses.
417 More importantly, it is inappropriate and selective to update line losses with 2010
418 data for purposes of the load forecast, yet not update all components of the load
419 forecast. This adjustment is a one-sided adjustment to reduce NPC without
420 appropriate corresponding updates or adjustments. OCS's recommendation also

421 conflicts with their own support of using a five-year average for line losses just a
422 year and a half ago without explaining what has changed.

423 **New Mexico LF Transmission Contract (OCS Adjustment 14)**

424 Mr. Falkenberg's adjustment of modeling the exchange contract with the City of
425 Redding as a "transfer" from the California-Oregon Border ("COB") to Four
426 Corners is inconsistent with the terms of the exchange contract. The Company
427 receives power at Four Corners from Redding's share of the San Juan generating
428 station located in New Mexico and in exchange delivers power to Redding at
429 COB. There is no transfer of energy from COB to Four Corners made possible by
430 this contract. The Commission should reject this adjustment.

431 **Outage-related Adjustments**

432 In the category of Outage-related adjustments Mr. Falkenberg has continually put
433 forth the argument through the years that these "one-time" events should not be
434 included in the four-year average because they are "unlikely" to occur in the test
435 period. However, as Mr. Falkenberg shows through his continued recommended
436 adjustments, these events do occur on a normal basis in the test period, they are
437 random, and they are completely unpredictable on any one unit. Therefore, Mr.
438 Falkenberg's claims that these events are "one-time" or unlikely are erroneous
439 considering the history of the Company's large fleet of thermal units. These
440 adjustments are selective and fail to recognize the excellent overall performance
441 of the Company's thermal fleet. They are also inconsistent with past Commission
442 precedent and previous testimony from Mr. Falkenberg.

443 **Lake Side Outage Rate (OCS Adjustment 21)**

444 OCS's adjustment is inconsistent with the Commission's finding that the EBA is
445 designed to capture forced outages. The adjustment is also selective and fails to
446 recognize the excellent performance overall of the Company's thermal fleet.

447 **Colstrip 4 Outage Rate (OCS Adjustment 21)**

448 OCS's adjustment is inconsistent with the Commission's finding that the EBA is
449 designed to capture forced outages. The adjustment is also selective and fails to
450 recognize the excellent performance overall of the Company's thermal fleet.

451 **Naughton 3 Outage Rate (OCS Adjustment 21 and UIEC Adjustment 13)**

452 OCS and UIEC make the argument that since the Company received liquidated
453 damages associated with contractor error at the Naughton 3 plant the outage
454 should be not recognized in the forced outage rate, because as they claim, it would
455 be "double counting." The collection of liquidated damages from the outage
456 repair does not displace the need to reflect appropriate outage durations in the
457 four-year average outage rate for the thermal unit in question. The Commission
458 should reject this adjustment.

459 **Cholla 4 Outage Rate (OCS Adjustment 21)**

460 OCS recommends an adjustment to the Cholla 4 outage rate associated with an
461 investment at the plant that was intended to improve the overall performance of
462 the facility. However, OCS witness Mr. Falkenberg has provided testimony in a
463 separate proceeding stating exactly the contrary; that it is more reasonable to
464 allow these types of improvements to be "...factored into the ratemaking process

465 in due course.”⁶ The Company agrees with this reasoning and recommends the
466 Commission object to this ad-hoc adjustment.

467 **Bridger Outage Rate (OCS Adjustment 21)**

468 OCS’s adjustment is inconsistent with the Commission’s finding that the EBA is
469 designed to capture forced outages. As explained by Cindy Crane, OCS assumes
470 the Company can get lower cost coal from underground mining at the same
471 quality of coal from higher price surface mining. Mr. Falkenberg attempts to
472 increase the quality of the coal without increasing the price. This is not possible.
473 Mr. Falkenberg also adjusts the Jim Bridger outage rate for outages due to
474 employee and contractor errors. Mr. Falkenberg fails to cite any imprudence with
475 these outages on behalf of the Company, and bases his adjustment on an
476 erroneous point that the outage rate associated with employee outages is “twice
477 the NERC average.” The Company provides the correct North American Electric
478 Reliability Corporation (“NERC”) average rate for Personnel Error cause codes,
479 and shows that Mr. Falkenberg has not only erred in his comparison and reported
480 NERC statistic, but also further illustrates the one sided nature of this adjustment.

481 **Heat Rate Modeling (DPU Adjustment 10 and OCS Adjustment 22)**

482 DPU’s and OCS’s modeling adjustment biases heat rates to be more efficient than
483 actual heat rates. This adjustment does not recognize the excellent overall
484 performance of the Company’s thermal fleet. The Commission should continue to
485 reject this adjustment, as it did in the 2009 GRC.

⁶ *Re Pub. Util. Comm’n of Or. Investigation into Forecasting Forced Outage Rates for Electric Generating Units*, Docket No. UM 1355, Direct Testimony and Exhibits of Randall J. Falkenberg, ICNU/100, Falkenberg/21 (Apr. 7, 2009).

486 **Reserve Shutdowns (OCS Adjustment 21 and UIEC Adjustment 2)**

487 This adjustment assumes that when a thermal unit is placed on reserve shut down,
488 due to economic displacement, had it been running it would have run 100 percent
489 of the time, thereby inflating the availability rate. This assumption is unreasonable
490 and illogical, as demonstrated by the fact that Mr. Falkenberg has agreed to the
491 Company's approach elsewhere. The Company calculates forced outage rates
492 consistent with the NERC industry standard formula.

493 **Miscellaneous Thermal Adjustments**

494 **Chehalis Reserve Capability (DPU Adjustment 11 and OCS Adjustment 15)**

495 The Company is currently unable to use the Chehalis plant to provide operating
496 reserves. The Company has been working on an arrangement with BPA to allow
497 Chehalis to provide operating reserves, but it is unclear whether these
498 arrangements will be finalized during the rate effective period. Without more
499 certainty, it is inappropriate to model operating reserve capability at Chehalis.

500 **Station Service Corrections (OCS Adjustment 16)**

501 Mr. Falkenberg proposes to change station service amounts included in GRID for
502 Chehalis, Currant Creek and Hunter. Station service in GRID is the amount of
503 power used by the power station when it is not generating. Mr. Falkenberg
504 removes all of the station service for Currant Creek and uses generation logs in
505 place of actual historic billings for Chehalis. Both of these adjustments are
506 unreasonable. The Company adopted Mr. Falkenberg's adjustment for Hunter.

507 **Cholla Reserve Capability (OCS Adjustment 17)**

508 Mr. Falkenberg accepts that the Commission adopted the Company's modeling of
509 Cholla Unit 4 in the previous general rate case, recognizing that Cholla 4 has a
510 physical transmission constraint at 387 MW. However, Mr. Falkenberg now
511 proposes to change the reserve carrying capability of the plant and has increased
512 the nameplate capacity of the plant to 395 MW in an attempt to get an equivalent
513 adjustment to the one rejected by the Commission. Mr. Falkenberg's adjustment
514 continues to exceed the physical transmission constraint.

515 **Hydro Adjustments**

516 **Lewis River Hydro Modeling (OCS Adjustment 8)**

517 Mr. Falkenberg proposes to remove the Company's modeling of Lewis River
518 Motoring and Efficiency Losses without challenging these adjustments on their
519 merit. His proposal to remove these legitimate adjustments is based on his "hydro
520 screening" methodology, which is flawed. Mr. Falkenberg's adjustment actually
521 shifts hydro generation to times when hydro units are off-line for forced outages.
522 The argument to remove the Company's modeling of Lewis River Motoring and
523 Efficiency Losses is misplaced and irrelevant.

524 **Remove Hydro Forced Outages (OCS Adjustment 9)**

525 OCS's adjustment to remove hydro forced outage rates, and instead calculate an
526 average energy value for the times that the Company was not able to dispatch the
527 hydro resource, is incorrect. OCS reflects a financial adjustment as if no water
528 was spilled during these forced outage events. In addition, OCS has adjusted the
529 value of this generation by making an arbitrary assumption in its financial

530 adjustment that the lost hydro generation would have been redispatched on an
531 average basis throughout the year. The Company shows that OCS's assumptions
532 on both counts are incorrect.

533 **Start Up Adjustments (OCS Adjustment 3)**

534 **Start Up Fuel**

535 The adjustment is illogical and one-sided. Start-up fuel costs are related to plant
536 start ups and have nothing to do with forced outages.

537 **Start Up Fuel Energy Value**

538 My direct testimony demonstrated that properly including energy produced during
539 start-up would increase NPC. On this basis, the Commission should continue to
540 reject this adjustment, as it did in the 2009 GRC.

541 **Balancing Adjustment (OCS Adjustment 23)**

542 The Company agrees that a final GRID run should be made with all of the
543 Commission ordered adjustments to the GRID model.

544 **Detailed Responses to NPC Adjustments**

545 **Wind Integration Adjustments**

546 **Wind Study Modeling (OCS Adjustment 1)**

547 **Q. Please summarize the Company's wind integration study.**

548 A. As discussed in my direct testimony, the Company performed an extensive study
549 on the impact of integrating wind generation into its resource portfolio. This Wind
550 Study identified additional reserve requirements in two categories: regulation
551 reserves that deal with load and wind variability in ten-minute intervals, and load
552 following reserves that deal with load and wind variability over a sixty-minute

553 time period. Both services respond to the up and down variations of wind
554 generation.

555 **Q. What costs has the Company included in NPC that are related to the**
556 **integration of wind resources within its balancing authority?**

557 A. The Company's wind integration costs during the test period are approximately
558 \$33.2 million on a total Company basis. This amount is reflected in Table 2 of
559 Mr. Falkenberg's direct testimony as the "Total Wind Integration Cost,"
560 excluding "Contingency Reserves" and "BPA Wind Integration charges."

561 **Q. What do these costs equate to on a cost per megawatt hour basis?**

562 A. When the \$33.2 million of wind integration costs are applied to the amount of
563 Company's wind generation within its balancing area over the test period, this
564 equates to \$6.49/MWh. This is in line with the \$6.62/MWh wind integration costs
565 approved in the 2009 GRC. While Mr. Falkenberg includes contingency reserve
566 costs in his Table, these costs should be excluded because they have nothing to do
567 with integrating variable energy resources such as wind.

568 **Q. What would the wind integration cost be if Mr. Falkenberg's recommended**
569 **adjustments were applied to NPC over the test period?**

570 A. The per unit cost of wind integration would drop from \$6.54/MWh to
571 \$3.05/MWh. This is less than one-half of the charge now reflected in rates,
572 although there is no evidence that the cost of integrating wind has materially
573 decreased since the 2009 GRC.

574 **Q. How do Mr. Falkenberg's costs compare to the wind integration charges**
575 **from BPA that are included in NPC?**

576 A. BPA integration costs total approximately \$3.1 million on a total Company basis
577 over the test period, which equates to \$5.34/MWh. Therefore, BPA's wind
578 integration costs are about one and half times the effective wind integration cost
579 that Mr. Falkenberg recommends

580 **Q. Are BPA's wind integration costs directly comparable to the Company's**
581 **wind integration costs included in NPC?**

582 A. No. Wind projects interconnected to BPA's system are also subject to generation
583 imbalance charges. The generation imbalance charges apply when there is a
584 difference between scheduled and actual generation. To the extent generation
585 exceeds scheduled energy amounts, the transmission customer receives a credit.
586 To the extent generation falls short of scheduled energy amounts, the transmission
587 customer is charged incremental costs. The amounts credited and charged are
588 applied within one of three different "deviation bands," with the cost and credit
589 amounts increasing as deviations from schedule increase. These generation
590 imbalance charges are in addition to BPA's \$5.34/MWh wind integration charge,
591 whereas the Company does not model an additional generation imbalance charge
592 on wind projects interconnected to its system.

593 Certain business practices implemented by BPA also carry wind
594 integration costs that are not included in the \$5.34/MWh wind integration charge.
595 For instance, under BPA's dispatcher's standing order #216 (DSO-216), BPA can
596 force curtailment of wind generation up to scheduled volumes if they run out of

597 regulation down reserves. Accounting for the revenue lost due to curtailment
598 under DSO-216 would increase the effective BPA wind integration cost of
599 \$5.34/MWh included in GRID.

600 **Q. Has the Company recently been subject to BPA’s dispatcher’s standing order**
601 **#216?**

602 A. Yes. The Company recently filed a petition with FERC associated with BPA’s
603 continued use of its standing order as the area has experienced a higher than
604 normal water year.

605 **Q. Has Mr. Falkenberg contested BPA wind integration costs included in NPC**
606 **over the test period?**

607 A. No.

608 **Q. Is the Company aware of any other available wind integration studies from**
609 **an electric utility?**

610 A. Yes. Portland General Electric (“PGE”) recently filed the preliminary results of its
611 wind integration study. According to its results, PGE estimates wind integration
612 costs of approximately \$14.46/MWh to integrate 850 MW of wind on its system.⁷
613 In comparison, the Company’s wind integration costs are less than half this
614 amount and are for a much higher level of wind generation.

⁷ See Exhibit RMP___(GND-3R), PGE handout, Wind Integration Study External Stakeholder Meeting, May 18, 2011, Slide 13.

615 **The Wind Study Process**

616 **Q. Please describe the process the Company followed in developing its Wind**
617 **Study.**

618 A. The Company developed the Wind Study over a nine-month period starting in
619 January 2010 and invited stakeholders to participate in and comment on each
620 phase of the process. Stakeholders had the opportunity to engage in the Wind
621 Study in several ways. The Company held public input meetings early in the
622 process allowing stakeholders to discuss and comment on the process, the key
623 concepts used to define the scope, and the methods that would be used to carry
624 out the Wind Study. Stakeholders were also provided with opportunities to
625 provide written comments in response to documents made available by the
626 Company on a dedicated website as the process progressed through the scoping,
627 methodology development, and implementation phases. The Company received,
628 carefully reviewed, and responded to all comments submitted by stakeholders
629 throughout the process.

630 **Q. What conclusions did Mr. Falkenberg make with regard to the Wind Study**
631 **process?**

632 A. Mr. Falkenberg concluded the Company failed to reflect the views and
633 criticisms of stakeholders who participated in the Wind Study.

634 **Q. Do you agree with Mr. Falkenberg’s conclusion that the Company did not**
635 **reflect the views and criticisms of stakeholders who participated in the Wind**
636 **Study?**

637 A. No. The Company carefully considered all recommendations made by
638 stakeholders who participated in the Wind Study process. There were numerous
639 instances where the Company agreed with the recommendations submitted by
640 stakeholders and incorporated them into the Wind Study. When comments from
641 stakeholders were received, the Company carefully reviewed each comment, and
642 as necessary counseled with the technical advisor hired by the Company to assist
643 with the Wind Study to evaluate whether any given recommendation might
644 improve the study design and overall validity of the study results.

645 It is neither feasible nor practical to expect that the Company would
646 have incorporated all of the stakeholder recommendations as the process moved
647 forward. All of the stakeholders did not agree with all aspects of the Wind
648 Study, making it impossible to incorporate the views and opinions of all of
649 those who participated in the process. While there were instances where the
650 Company did not agree with the recommendations made by stakeholders, at no
651 time did the Company intentionally suppress the views and criticisms of any of
652 the stakeholders with the intentions of driving the Wind Study to a
653 predetermined outcome.

654 **Q. Have other stakeholders in the process commented favorably on the Wind**
655 **Study?**

656 A. Yes. Mr. Brendan J. Kirby, a consultant and witness for the Interwest Energy
657 Alliance in Wyoming, made the following comments about the Company's new
658 wind study:

659 ...looking at the proposed study for this next upcoming integration
660 study, it's greatly improved. They're proposing to incorporate wind
661 and load variability and even certainty. They're running a full
662 production cost simulation. There is a more open review process,
663 though it's not a full technical review committee, and the
664 discussions they're going to be having with my colleague Michael
665 Milligan should be productive. There are concerns with the
666 specifics of the implementation, but those are being discussed
667 through the stakeholder process.

668 Transcripts from Wyoming Public Service Commission Docket No. 20000-352-
669 ER-09, Vol. 3, page 568.

670 **Q. Mr. Falkenberg suggests that the Company "...proposed an early completion**
671 **date for the study so that it could be included as an update in the Oregon and**
672 **Washington rate cases." Is he correct?**

673 A. No. As discussed in the Wind Study workshops, the Oregon Public Utility
674 Commission ("Oregon Commission") required the Company in Order No. 10-066
675 to complete a Wind Study by August 2, 2010. PacifiCorp initiated its public
676 participation process with a public stakeholder meeting on February 26, 2010 to
677 discuss the general framework and methodology for the Wind Study. The
678 Company provided its draft 2010 Wind Study methodology paper on April 16,
679 2010, a revised draft methodology study on April 28, 2010, and a third draft
680 methodology study on May 19, 2010 based on comments received from

681 stakeholders and The Brattle Group. The Company filed a motion with the
682 Oregon Commission to extend the Wind Study due date to September 1, 2010 to
683 accommodate more stakeholder study review time, and allot the Company
684 additional time to investigate and validate modeling results.

685 **Q. Did the Oregon Commission's imposed timeframe play a factor in your**
686 **decision to hire the technical advisor The Brattle Group, instead of using a**
687 **technical advisory committee as suggested by Mr. Falkenberg?**

688 A. Yes. A technical advisory committee takes additional timing and planning in
689 order to be able to accommodate the numerous scheduling issues that will arise
690 when attempting to bring together multiple parties from different time zones and
691 working constraints. The Company believes that The Brattle Group provided a
692 thorough and objective independent review of the Wind Study. In the action plan
693 for the 2011 IRP, the Company indicated it will be forming a technical review
694 committee as part of its next wind integration study.

695 **Q. Does the Company believe that its Wind Study results are accurate and**
696 **complete?**

697 A. Yes. The timing constraints imposed by the Oregon Commission did not affect
698 the Company's ability to produce an accurate Wind Study that verifiably depicts
699 the Company's costs of integrating wind into its system.

700 **Wind Study Regulating Margin**

701 **Q. Please summarize the conclusions in Exhibit OCS 4D of Mr. Falkenberg's**
702 **direct testimony related to the amount of regulating margin the Company**
703 **included in the test period.**

704 A. Mr. Falkenberg describes what he perceives to be deficiencies in the Wind Study,
705 which served as the Company's basis for establishing the amount of regulating
706 margin used in the test period. For each of these perceived deficiencies, Mr.
707 Falkenberg introduces new assumptions and methods that differ from those used
708 in the Wind Study to arrive at his own estimate of regulating margin. After
709 applying his own assumptions and methods, Mr. Falkenberg establishes his own
710 estimate for regulating margin for purposes of forecasting NPC in GRID.

711 **Q. What is regulating margin, and why does the Company include regulating**
712 **margin when forecasting NPC in GRID?**

713 A. I describe in my direct testimony that the Company, in its role of balancing
714 authority, must match system resources to actual load and generation fluctuations
715 on a moment-to-moment basis to maintain system reliability and system
716 frequency. The Company accomplishes this with operating reserves by setting
717 aside capacity that can be called upon in response to fluctuations in load and
718 generation. Fluctuations in generation from variable energy resources such as
719 wind introduce incremental variability and uncertainty, thereby increasing the
720 amount of reserves that the Company must set aside. The regulating margin in
721 GRID represents the amount of operating reserves needed to maintain reliability
722 given variability and uncertainty from both load fluctuations and wind

723 fluctuations. This reserve capacity cannot be used to serve load or be used to
724 make market sales and represents a portion of the cost of reliability in the NPC
725 forecast.⁸

726 **Q. What does Mr. Falkenberg recommend as the appropriate level of**
727 **regulating margin in GRID?**

728 A. Mr. Falkenberg concludes that regulating margin assumptions in GRID should be
729 set to 430 average MW, which is 103 average MW lower than the 533 average
730 MW of regulating margin used by the Company over the test period and 199 MW
731 lower than what the Company actually held for regulation purposes in 2010.

732 **Q. How do you respond?**

733 A. I disagree with Mr. Falkenberg's conclusions. As described above, the Company
734 produced its Wind Study over the course of approximately nine months in 2010,
735 utilizing a robust public process. Over this period, the Company received no
736 comments or recommendations from Mr. Falkenberg, and received no comments
737 from other parties addressing the concerns raised in Exhibit OCS 4D of Mr.
738 Falkenberg's direct testimony. As such, the changes in assumptions and
739 methodology that have been introduced by Mr. Falkenberg should not be
740 considered because there is insufficient opportunity for review, not only by the
741 Company and its technical advisor, but also for those stakeholders that chose to
742 engage in the Wind Study process, including a number of Utah parties.

⁸ In addition to regulating margin, NPC forecasts reflect reliability costs from the requirement to carry contingency reserves as defined in the WECC Standard BAL-STD-002-0. The same standard defines a requirement for regulation reserves or load following reserves as "sufficient regulating margin to allow the balancing authority to meet NERC's control performance criteria."

743 **Q. Can the Company support its forecasted need for regulating margin with**
744 **historical data?**

745 A. Yes. While the Company does not record the amount of regulating reserves
746 independently from spinning reserves, it can estimate the amount of regulating
747 reserves that were actually being carried for a given period of time.⁹

748 **Q. How would the Company estimate the amount of regulating reserves being**
749 **carried?**

750 A. The Company has data showing the amount of spinning and non-spinning
751 reserves credited to individual resources and contracts by hour. The Company
752 also has data showing the amount of contingency reserves that were required to
753 meet the WECC Standard BAL-STD-002-0, which defines contingency reserves
754 as:

755 The sum of five percent of the load responsibility served by hydro and
756 wind generation and seven percent of the load responsibility served by
757 thermal generation.

758 Any spinning reserve amounts being held on resources and contracts in excess of
759 the spinning reserves required by the WECC Standard BAL-STD-002-0 net of
760 any non-spinning reserve shortfalls would indicate the amount of surplus spinning
761 reserves available for regulation margin.¹⁰

762 **Q. Would such a calculation also include the amount of load following**
763 **reserves needed to meet NERC's control performance criteria?**

764 A. No. However, an additional calculation is done to estimate the amount of load
765 following reserves available for a given period of time. Unlike regulating

⁹ Regulating reserves are a subset of the spinning reserves recorded.

¹⁰ Spinning reserves can be used to meet non-spinning reserve requirements to satisfy the requirements under WECC Standard BAL-STD-002-0.

766 reserves, which are used to manage *variability* in loads and generation over
767 relatively short time periods, load following reserves are used to manage
768 *uncertainty* in load and generation over longer time periods. For purposes of the
769 Wind Study, regulation reserves are defined using 10-minute periods and load
770 following reserves were defined using 60-minute periods. Thus, the amount of
771 regulation reserves that can be held on a resource is based on how fast the unit can
772 ramp over a 10-minute period. Similarly, the amount of load following reserves
773 that can be held on a resource is based on how fast the unit can ramp over a 60-
774 minute period. However, in either instance, the regulation or load following
775 reserve capability of any given resource can never exceed the difference between
776 that resource's minimum operating capability and the maximum dependable
777 capability ("MDC"). These principles are applied to estimate the amount of load
778 following reserves that were available to operations over any given period of
779 time.

780 **Q. Please explain.**

781 A. Data that identifies the amount of spinning reserves held can be used along with
782 actual generation data and MDC data to derive the amount of load following
783 reserves that were available over the chosen historical period. Given the time
784 period defining load following reserves is six times the time period used to define
785 spinning reserves, the amount of load following reserves would be six times the
786 spinning reserves being held or the difference between actual generation plus
787 spinning reserve held and the MDC, whichever is less.

788 For example, a 500 MW resource with a 5 MW/minute ramp rate could
789 provide 50 MW of spinning reserves in response to variations in system load and
790 generation over a 10-minute period (5 MW/minute x 10 minutes = 50 MW). If
791 this unit had a minimum operating capability at or below 200 MW, it is capable of
792 providing up to 250 MW of load following reserves in response to unexpected
793 changes in system load and generation over a 60-minute period (5 MW/minute x
794 60 minutes less 50 MW of spinning reserves being used to manage variability
795 over 10-minute periods).¹¹ However, if this resource were being used to generate
796 400 MW, the load following reserve capability would be reduced to 50 MW
797 owing to the fact it could not exceed its 500 MW rating (minimum of 250 MW of
798 load following capability or the difference between the 400 MW actual generation
799 level and 500 MW rating less 50 MW of spinning reserves = 50 MW).

800 **Q. Has the Company performed this calculation?**

801 A. Yes. Using hourly data from calendar year 2010, this calculation shows the
802 company held 344 average MW of regulating reserves and 284 average MW of
803 load following reserves. Since these values are derived from actual data, the
804 results are perfectly correlated, and can be summed directly for a total regulating
805 margin of 629 average MW.

¹¹ The full 300MW of load following capability could not be used to manage 60-minute uncertainty without compromising the amount of spinning reserves being held. As such, the 30MW of spinning reserves is netted against the load following capability to arrive at the amount of load following reserves that can be used.

806 **Q. In DPU's critique of the Wind Study, Mr. Evans provides a chart that shows**
807 **"Average Spinning Reserves" for 2007 through 2010. Is he correct in his**
808 **chart and analysis that the Company has "greatly exaggerated the need for**
809 **additional spinning reserves?"**

810 A. No. What Mr. Evans fails to acknowledge is that "Spinning reserves", or ten-
811 minute reserves as the Company terms them, are only one piece of the regulation
812 reserves required to follow load and wind generation facilities. As discussed
813 above, the Company also requires load following reserves in order to maintain
814 compliance with the mandatory reliability standards established by NERC. Mr.
815 Evans incorrectly attributes the increase in reserves in GRID to 10-minute
816 reserves, when in fact, the 533 MW of reserves modeled in GRID is for both 10-
817 minute reserves and load following reserves.

818 **Q. How does this analysis of actual operations in 2010 support the 533 average**
819 **MW of regulating margin included in GRID for the test period?**

820 A. The result of the historical analysis using 2010 data is higher than the 533 average
821 MW regulating margin amount used in GRID. This analysis lends support to the
822 533 average MW of regulation margin forecast for the test period and further
823 shows that the estimated amount of regulation margin proposed by Mr.
824 Falkenberg is too low.

825 **Q. Mr. Evans claims that using 533 average MW of reserves in GRID will cause**
826 **an exaggeration of the level of reserves required. Do you agree?**

827 A. No. GRID is a forecasting model that assumes perfect system operations; it does
828 not include the variability associated with wind. In order to appropriately model

829 the reserves the Company uses an average MW figure in every hour of the test
830 period. Mr. Evans implies that there are hours in which 533 MW of reserves is not
831 necessary and too high. However, using an average works in two directions—
832 while the level of reserves in some hours may be lower there are also a
833 corresponding number of hours in which they will be higher.

834 **Wind Study Must-run Assumptions (OCS Adjustment 2 and UIEC Adjustment 3)**

835 **Q. Did Messrs. Falkenberg and Widmer agree with the Company's must-run**
836 **settings as applied to Gadsby units 4-6 and Currant Creek in GRID?**

837 A. No. Mr. Falkenberg suggests that plant start-up data for calendar year 2010 does
838 not support the must-run settings applied to Gadsby units 4-6 and further contends
839 that start-up data for Currant Creek does not support must run settings for both of
840 the Currant Creek CTs.¹² Mr. Widmer contests the must-run settings for Gadsby
841 units 4-6, but does not contest the must-run setting for Currant Creek.

842 **Q. How do you respond?**

843 A. I disagree with Mr. Falkenberg's and Mr. Widmer's conclusions. While it is true
844 that a must-run setting forces Gadsby units 4-6 and Currant Creek to operate in all
845 hours, the must-run setting also ensures that these gas units are committed and
846 able to carry reserves as is often done in real time operations. When the must-run
847 setting is applied, units are committed and required to run at minimum levels,
848 leaving GRID with the option to use the remaining capacity (the capacity
849 differential between the minimum and the maximum rating) for reserves, to serve
850 load, or to support economic market sales.

¹² The Currant Creek plant is a 2x1 combined cycle facility with two combustion turbines and a heat recovery steam generator.

851 **Q. Mr. Falkenberg states that GRID considers reserve requirements in**
852 **modeling commitment decisions. Do you agree with this characterization?**

853 A. No, this is misleading. GRID does consider the relative cost of reserves among
854 available resources in its commitment logic. However, in making its commitment
855 decisions, GRID does not recognize differences in the operational flexibility from
856 reserves held on gas units relative to the operational flexibility from reserves held
857 on coal units. Gas units are much more flexible than coal units and can respond
858 better to short-term variations in wind generation. When managing system
859 variability over relatively short time periods, from an operational perspective, 30
860 MW of spinning reserves held on a flexible gas unit is not the same as 30 MW of
861 spinning reserves held on an inflexible coal unit. The must-run settings in GRID
862 ensure that flexible resources are available to carry reserves that can best respond
863 to short term variations in wind generation as implemented in real operations.

864 **Q. Is Mr. Falkenberg's review of gas plant start-ups appropriate in**
865 **determining that the must-run settings are not supported by operational**
866 **data?**

867 A. No. While the start-up data indicates that Gadsby units 4-6 tend to cycle and
868 that one of the Currant Creek CTs cycles, albeit less frequently than the Gadsby
869 units, the start-up data in and of itself does not show how generation from these
870 units with must-run settings in GRID over the test period compare to historical
871 generation data. Relative to generation in 2009, the period of historical data
872 reviewed when the use of must-run settings were first implemented in the Wind
873 Study, the average capacity factors for Gadsby units 4-6 and Currant Creek in

874 GRID compare well to the average capacity factors derived from historical
875 operational data. Over the test period in the Company's filed NPC, with must-
876 run settings turned on, GRID yields a 33 percent average capacity factor for
877 Gadsby units 4-6 and a 63 percent capacity factor for Currant Creek. In 2009,
878 Gadsby units 4-6 were operated at a 33 percent capacity factor and Currant
879 Creek was operated at a 65 percent capacity factor. As such, the must-run
880 settings applied in GRID result in generation that is consistent with actual
881 operational practice.

882 **Wind Integration Contingency Reserves**

883 **Q. Can you describe Mr. Falkenberg's and Mr. Evan's position on how the**
884 **Company applied contingency reserves for wind resources?**

885 A. Yes. Mr. Falkenberg and Mr. Evans are of the opinion that the cost for
886 contingency reserves associated with wind resources is not justified because the
887 variability in wind generation used to derive regulating margin already reflects
888 unit outages. Based on this opinion, Mr. Falkenberg and Mr. Evans conclude that
889 costs for contingency reserves amounts to double counting of requirements and
890 argue that these costs should be removed from NPC.

891 **Q. Is this position valid?**

892 A. No. Reliability standards require the Company to carry contingency reserves for
893 five percent of the load responsibility served by wind. The likelihood of an outage
894 at wind facilities has no bearing on this requirement. Further, outage rates on
895 individual turbines are relatively low, and thus any influence outages might have
896 had in the determination of the regulating margin used in GRID would be

897 minimal. Mr. Falkenberg himself states in his direct testimony, "...wind projects
898 consist of dozens of independent turbines, each with fairly low outage rates."

899 **Non-Owned Wind Facilities (DPU Adjustment 5)**

900 **Q. What has the DPU proposed with respect to wind integration costs related to**
901 **non-owned wind facilities?**

902 A. DPU argues that the Company should not recover wind integration costs
903 associated with providing wind integration services to non-owned projects. This
904 adjustment would reduce total Company NPC by \$4 million.

905 **Q. Did you discuss this adjustment in your direct testimony?**

906 A. Yes. The Commission requested that the Company provide additional information
907 on this issue in their Order in the Company's 2009 GRC, so I discussed this
908 adjustment in my direct testimony in this docket. I explained why the Company is
909 required to provide wind integration service to wholesale customers under federal
910 law, that the Company's OATT does not allow the Company to charge for this
911 service, and that customers benefit from the Company being a balancing area
912 authority and the revenues associated with wheeling for wholesale customers.
913 Because the Company is a balancing area authority, retail customers benefit by
914 having access to Company-owned transmission as a network customer to serve
915 load and transact in the wholesale markets. The transmission system provides
916 delivery of high-voltage power to approximately 1.7 million PacifiCorp customers
917 as well as non-affiliated utilities and other entities. The system transmits
918 electricity through approximately 15,700 miles of transmission lines across 10
919 states in the western United States. The system is interconnected with more than

920 83 generating plants and 12 adjacent control areas at 153 interconnection points.
921 If the Company did not own such a vast transmission network and did not operate
922 its own balancing area, retail customers would be subject to additional wheeling
923 expenses from third parties under their OATT rates. In the recent past, we have
924 seen wheeling expenses increase over \$20 million annually with respect to BPA
925 and Idaho Power as they moved the Company from legacy wheeling contracts to
926 more expensive OATT service.

927 **Q. You stated in your direct testimony that the Company plans to file a rate case**
928 **with FERC no later than June 1, 2011, in which the Company will include**
929 **updated charges for ancillary services needed to integrate wind, pending**
930 **FERC guidance on the issue. Did the Company file its FERC rate case?**

931 A. Yes. These issues are now pending before FERC. Under these circumstances,
932 there is no basis for the Commission to change its ruling in the 2009 GRC
933 allowing recovery of wind integration costs for non-owned wind.

934 **Q. Do you have anything to add to your direct testimony?**

935 A. Yes. I have been advised that because FERC has exclusive authority over the
936 transmission and sale of electricity in interstate commerce pursuant to the Federal
937 Power Act, under the Supremacy Clause of the United States Constitution “a state
938 utility commission setting retail rates must allow, as reasonable operating
939 expenses, costs incurred as a result of paying a FERC-determined wholesale price
940 . . . Once FERC sets such a rate, a State may not conclude in setting retail rates
941 that the FERC-approved wholesale rates are unreasonable.”¹³ Correspondingly,

¹³ *Nantahala Power and Light Co. v. Thornburg*, 476 U.S. 953, 956-966 (1986).

942 the Supremacy Clause would also require a state commission to allow as
943 reasonable operating expenses costs that are incurred as a result of operating
944 consistent with a FERC-approved tariff. Based upon these principles, I understand
945 that because the Company is required by federal law to interconnect with
946 wholesale transmission customers under the terms of the OATT, federal
947 preemption precludes disallowing the associated costs, such as the costs of wind
948 integration services.

949 **Market Caps Adjustment (DPU Adjustment 6, OCS Adjustment 18, and UIEC**
950 **Adjustment 17)**

951 **Q. What have the parties proposed with respect to GRID market caps?**

952 A. DPU, OCS, and UIEC propose changes to the Company's market cap
953 methodology. DPU proposes to remove market caps in all major markets except
954 for the Mona market, resulting in a \$5.3 million reduction to system NPC. UIEC
955 proposes to remove market caps in all major markets except for the Mona market,
956 resulting in a \$5.5 million reduction to system NPC. OCS proposes to limit
957 market caps to the five-hour graveyard shift, resulting in a \$3.7 million reduction
958 to system NPC.

959 **Q. How did the parties evaluate whether market caps continue to be relevant?**

960 A. DPU, OCS, and UIEC all evaluated the 48-month historical average of coal
961 generation to determine whether market caps are necessary to prevent GRID from
962 modeling too much coal generation. However, DPU, OCS and UIEC failed to
963 account for the impact of integrating wind generation on coal generation, despite

964 the fact that the Company has offered clear evidence¹⁴ that modeling wind
965 integration reserves in GRID reduces coal generation as compared with historical
966 actuals. In addition, all three parties fail to acknowledge or rebut the lack of
967 liquidity or market depth at the specific hubs, not only during off-peak hours, but
968 also during on-peak hours. This lack of liquidity was supported by the Company
969 in its direct testimony as the primary reason for the continued use and further
970 refinement of market caps.

971 **Q. UIEC argues that the Company has not justified the change in its market cap**
972 **methodology. How do you respond?**

973 A. As explained in my direct testimony, the Company continues to take a reasonable
974 approach in its determination of market depth. Utilizing historical short-term firm
975 transactions during the same 48-month period on which availability of the thermal
976 generation is based, the Company determined the average available sales at each
977 market in each hour and then reduced the market depths by the quantity of short-
978 term firm transactions that the Company has included in the normalized NPC
979 study for the test period in all sales markets.

980 **Q. UIEC argues that if the Company has more energy to sell, it will sell more**
981 **than it did during the historical period. Is this true?**

982 A. No. UIEC's argument is nonsensical; if in the past the Company has not been able
983 to make additional sales, it is not reasonable to assume that they will be made in
984 the future, barring any new information or changes in the market. In any event,

¹⁴ In its response to DPU data request 10.37, the Company showed that without modeling incremental reserve requirement to integrate wind generation, with the same market caps as in the Company's direct filing the coal generation would be approximately 45 million MWh, and higher than the average historical generation quoted by parties.

985 this position is contrary to the Commission's directive that it will look to
986 historical trends and actual, verifiable experience as appropriate to determine the
987 NPC forecast in this case.

988 **Q. Has UIEC or DPU provided any new information that would show that the**
989 **Company would be able to make additional sales in the test period above**
990 **historical levels in the hours in which market caps are applied?**

991 A. No.

992 **Q. Is it reasonable to revert to the prior method of market cap modeling in**
993 **GRID, as suggested by OCS?**

994 A. No. As described in my direct testimony, the Company performed an analysis
995 based on a 48-month period. OCS has not discounted this method and has
996 provided no information that would suggest that the Company's determination of
997 market liquidity is incorrect. OCS simply claims that the analysis should be
998 reflected only in the graveyard hours to arbitrarily reduce NPC.

999 **Trading and Arbitrage Adjustment (DPU Adjustment 9 and OCS Adjustment 5)**

1000 **Q. What have DPU and OCS proposed with respect to arbitrage sales margins?**

1001 A. DPU and OCS argue that GRID does not account for margins earned on arbitrage
1002 and trading transactions, and propose to reflect an estimate of arbitrage and
1003 trading margins based on the annual average from July 2006 through June 2010,
1004 which reduces NPC by \$3.0 million on a total Company basis.

1005 **Q. Why do DPU and OCS claim such an adjustment is necessary?**

1006 A. DPU and OCS argue that the Company will engage in arbitrage and trading
1007 transactions in the test year, but revenues from arbitrage and trading transactions

1008 are not included in GRID.

1009 **Q. Do you agree that arbitrage revenues are not included in GRID?**

1010 A. No. GRID fully utilizes the transmission included in the model to make arbitrage
1011 transactions through system balancing sales and purchases. There are many hours
1012 when GRID is simultaneously purchasing power from one market and selling to a
1013 different market at a higher price. By definition, this is arbitrage. As a result, NPC
1014 are lower than they otherwise would be without these arbitrage transactions. In
1015 GRID, system balancing sales and purchases act as a proxy for future short-term
1016 firm sales and purchases, including arbitrage transactions, and are eventually
1017 replaced with real transactions. This adjustment proposes to impute arbitrage
1018 profits from historic transactions and would add to arbitrage profits that are
1019 already computed by GRID. DPU's and OCS's adjustments would double count
1020 revenues associated with these transactions. This adjustment is a selective and
1021 inconsistent departure from normalized NPC modeling.

1022 **Q. How do you know that these arbitrage transactions are already reflected in**
1023 **GRID?**

1024 A. If one were to look at the hourly results of the GRID model, they would see that
1025 there are simultaneous purchases and sales in the same hour where purchase
1026 prices are lower than sales prices.

1027 **Wheeling Adjustments**

1028 **Cal ISO Wheeling and Service Fees (DPU Adjustment 7, OCS Adjustment 10, and**
1029 **UIEC Adjustment 1)**

1030 **Q. Please describe DPU's, OCS's, and UIEC's adjustments to Cal ISO fees.**

1031 A. The parties recommend removal of the Cal ISO wheeling expenses and fees. They
1032 claim that the Cal ISO system capability is not modeled in GRID and there are no
1033 Cal ISO wholesale transactions included in the filing. DPU and OCS each
1034 propose a \$4.3 million reduction to total-Company NPC, while UIEC proposes a
1035 \$4.2 million reduction.

1036 **Q. Will the Company enter into transactions with the Cal ISO in the rate**
1037 **effective period?**

1038 A. Yes. DPU, OCS, and UIEC have not argued otherwise.

1039 **Q. Is Mr. Widmer correct that the Company executes transactions with the Cal**
1040 **ISO because these transactions provide the highest level of margin available**
1041 **at the time of execution?**

1042 A. No. The Company enters into transactions with the Cal ISO to serve load, not to
1043 earn a margin. The Company will enter into transactions with the Cal ISO if the
1044 Cal ISO is the Company's most economic option to serve load at that time. As a
1045 result, eliminating the Cal ISO as a counterparty will require the Company to
1046 enter into higher-priced transactions to serve load, thereby increasing NPC.

1047 **Q. If it is clear that the Company will engage in transactions with the Cal ISO in**
1048 **the future, what is the basis for the parties' adjustment?**

1049 A. DPU, OCS, and UIEC claim that the benefits associated with the Cal ISO

1050 transactions are not reflected in NPC.

1051 **Q. Are they correct?**

1052 A. No. This is evidenced by the fact that removing the Cal ISO as a counterparty
1053 would limit the Company's ability to fully utilize the market and cause NPC to
1054 increase. The retooling of GRID that would be required to remove Cal ISO as a
1055 counterparty would result in increased costs elsewhere, because the Company
1056 would need to find a way to replace the transactions it makes with the Cal ISO.
1057 The premise of the parties' adjustment that there would be a net benefit that
1058 would offset Cal ISO expenses or even reduce NPC is wrong. The benefit of
1059 doing business with the Cal ISO is to avoid doing something more expensive in
1060 order to serve load. If the Commission were to disallow Cal ISO fees as a
1061 legitimate expense, the Company would be forced to find alternatives to doing
1062 business with the Cal ISO.

1063 **Q. Why are there no Cal ISO transactions in the filing?**

1064 A. At this point, for the test period of 12-month ending June 2012, no transactions
1065 with deliveries in the test period have been completed. This is because the
1066 Company primarily transacts with the Cal ISO in the real-time and short-term
1067 markets. Historical trends and the Company's actual verifiable experience
1068 demonstrate that the Company regularly transacts with the Cal ISO in order to
1069 serve load in a reliable and cost-effective manner.

1070 **DC Intertie (OCS Adjustment 10 and UIEC Adjustment 8)**

1071 **Q. Please explain OCS's and UIEC's proposed adjustment to costs associated**
1072 **with the DC Intertie.**

1073 A. OCS and UIEC argue that costs associated with the DC Intertie and Network
1074 Transmission Agreement between BPA and the Company should be removed
1075 from NPC on the basis that no contracts included in the test year require the DC
1076 Intertie, and no purchases are modeled at the Nevada-Oregon Border ("NOB"),
1077 the point from which the agreement provides wheeling. UIEC goes so far as to
1078 claim it is not used and useful for the test year, although both OCS and UIEC
1079 admit it is used in actual operations. OCS's proposed adjustment would result in a
1080 \$4.8 million decrease to total Company NPC, while UIEC's adjustment would
1081 result in a \$4.7 million adjustment to total Company NPC.

1082 **Q. Please provide some background on the DC Intertie contract.**

1083 A. The DC Intertie contract was executed 17 years ago on May 26, 1994, to provide
1084 deliveries of 200 MW of power from Southern California Edison at NOB under
1085 Amendment 1 to the Winter Power Sales Agreement ("WPSA"). The WPSA was
1086 executed on December 14, 1993 and provided up to 422 MW of power to be
1087 delivered to the Company's west control area. At the time the WPSA was
1088 executed, the Company had sufficient transmission rights to import 222 MW of
1089 power into the west control area. The agreement provided that if the Company
1090 procured additional transmission rights by June 1, 1993, then it could import the
1091 remaining 200 MW to its system. The Company secured the remaining 200 MW
1092 of transmission rights by acquiring 200 MW of transmission capacity on the DC

1093 intertie. The Company terminated the WPSA effective January 1, 2002, but the
1094 DC Intertie contract remained effective by its terms.

1095 **Q. How does the DC Intertie contract benefit the Company’s customers today?**

1096 A. The agreement takes advantage of the load diversity between summer-peaking
1097 California and the winter-peaking Pacific Northwest. The contract provides a
1098 valuable means of securing capacity and energy from California entities to meet
1099 retail loads. Loads in California are relatively low in the winter when loads in the
1100 Company’s west control area and the rest of the Pacific Northwest are at their
1101 highest.

1102 **Q. Is there evidence that the Company can reasonably expect to use the DC
1103 Intertie in the rate effective period, even though GRID does not model
1104 transactions at NOB?**

1105 A. Yes. The Company made over 200 power purchase transactions at NOB each year
1106 for the past five years. The DC Intertie is used to transfer this power to load.
1107 There is no reason to believe this historical trend will not continue into the future.

1108 **Q. Can you quantify the benefit of those transactions as it compares with the
1109 cost of the contract?**

1110 A. The cost of the DC Intertie contract is \$1.99 per kilowatt-month, which compares
1111 to over \$8 per kilowatt-month that the Company pays to BPA under the peak
1112 purchase contract.

1113 **Q. What would be the result if the DC Intertie were not available to the
1114 Company?**

1115 A. If the DC Intertie were not available to the Company, then it would have to be

1116 replaced with a new 200 MW resource. Without a new 200 MW resource, the
1117 Company could not serve peak loads. Acquiring a new 200 MW transmission
1118 resource would cost customers significantly more than the cost of the DC Intertie.

1119 **Q. If the contract costs more than the dollar benefit of the transactions that use**
1120 **the contract, why is it appropriate to include the full costs of the DC Intertie**
1121 **agreement in rates?**

1122 A. In making its proposal, OCS and UIEC focus on energy deliveries under the
1123 contract rather than the capacity deferral and diversity benefits of the contract. It
1124 would be inappropriate to penalize the Company for prudently acquiring
1125 transmission rights 17 years ago by disallowing costs today based on hindsight
1126 and only looking at the energy value of a resource that can facilitate the delivery
1127 of both capacity and energy. By purchasing these transmission rights, the
1128 Company has purchased assurance that it can reliably serve its retail customers
1129 loads. OCS's and UIEC's proposals are based on a limited energy-only view of
1130 this contract is similar to arguing that the Company should only be able to recover
1131 insurance premiums when it receives proceeds under an insurance policy. The
1132 costs associated with this contract are modest in light of the benefit to the
1133 Company's overall transmission strategy and hedge against changes in the
1134 market.

1135 **Q. Is there an analogy that can be drawn to the CoolKeeper program in Utah?**

1136 A. Yes. The CoolKeeper program does not provide significant energy "benefits" in
1137 the test year. Its primary value is based on its capacity contribution which allows
1138 the Company to defer resources over time. No party has proposed to remove the

1139 CoolKeeper program costs because there are not offsetting benefits modeled in
1140 the test year.

1141 **Q. How should the Commission judge the prudence of this contract?**

1142 A. Prudence should always be judged based on the information that was known at
1143 the time the contract was executed. It would not be reasonable to judge a 17-year
1144 old contract based on information that is available today that was not available 17
1145 years ago.

1146 **Centralia Point-to-Point (OCS Adjustment 10 and UIEC Adjustment 9)**

1147 **Q. Do OCS and UIEC propose an adjustment similar to the DC Intertie**
1148 **adjustment related to the Centralia Point-to-Point (“PTP”) wheeling**
1149 **contract?**

1150 A. Yes. OCS proposes that the PTP contract be removed from rates, resulting in an
1151 \$11.0 million decrease to total Company NPC. UIEC proposes that all but about
1152 30 MW of the contract be excluded from rates, resulting in a \$10.9 million
1153 decrease to total Company NPC.

1154 **Q. What are the parties’ arguments in support of this adjustment?**

1155 A. OCS claims that the purpose of this contract was to wheel energy from the
1156 Centralia plant to the Company load centers, but energy purchase contracts from
1157 Centralia ended in 2010. OCS also argues that there are no transactions modeled
1158 in the test year that require this resource and that the Company has not provided
1159 any documentation supporting the reasons why it failed to coordinate the
1160 termination date of the wheeling contract with the Centralia purchase. UIEC also

1161 argues that the contract is only being used to the extent that a portion of a contract
1162 has been redirected to other paths.

1163 **Q. Please provide some background on the Centralia Point-to-Point wheeling**
1164 **contract.**

1165 A. In April 2007, the Company entered into a power purchase agreement with
1166 TransAlta with a delivery rate of up to [REDACTED] per hour for the three and one
1167 half year period ending December 31, 2010. The power was delivered to the
1168 Company at the C. W. Paul (“Paul”) substation located near the Centralia Coal
1169 plant in Centralia, Washington. The Company needed to enter into a new
1170 wheeling contract with BPA to move the power from the Paul substation to
1171 various load pockets in Oregon and Washington because the Company’s Formula
1172 Power Transmission (“FPT”) wheeling contract with BPA was expiring on June
1173 30, 2007. BPA was no longer offering FPT service at that time and required the
1174 Company to take new service under a PTP contract at prices specified in BPA’s
1175 Open Access Transmission Tariff (“OATT”).

1176 **Q. How was the new PTP contract structured?**

1177 A. In order to meet load, the 638 MW contract capacity was distributed as follows:

Transmission Path	Transmission quantity
C.W. Paul to Alvey	217 MW
C.W. Paul to Midway	100 MW
C.W. Paul to Reston	63 MW
C.W. Paul to Troutdale	250 MW
C.W. Paul to Woodland	8 MW

1178 **Q. Why did the Company chose a five-year term for the wheeling contract when**
1179 **the power purchase was only for three and one half years?**

1180 A. The Company elected a five-year term to assure that it had firm rights to serve
1181 load during a period of potential change to the resource and transmission portfolio
1182 mix and to reduce exposure to the number of parties challenging and competing
1183 for the same transmission capacity. At the time of execution, a five-year term was
1184 perceived to be the standard term for transmission service agreements that would
1185 continually be rolled over, so it discouraged any other party from competing.

1186 **Q. Please explain.**

1187 A. Because the Company had an existing FPT contract, it had the right to convert it
1188 to a PTP contract. Once that election was made, however, BPA had 30 days to
1189 determine if there were any qualified challengers in BPA's Open Access Same-
1190 Time Information System ("OASIS") queue. A qualified challenger would have
1191 to sign a contingent transmission service agreement and make a financial
1192 commitment to purchase transmission from Paul to various points within BPA's
1193 network system with a term longer than the term of the Company's offer. If that
1194 happened, the Company would have had 15 days to match the competing offer
1195 which could have had a term longer than five years thereby forcing the Company
1196 to execute a more than five-year term transmission agreement to facilitate the
1197 TransAlta purchase.

1198 **Q. Why should customers continue to pay for the Centralia PTP contract after**
1199 **the long-term purchase of power has terminated and was not renewed?**

1200 A. At the time the Company entered into the point-to-point contract, it viewed

1201 purchases from Centralia as a viable long-term source of power to meet its loads,
1202 especially given the ability to deliver that power directly to five separate load
1203 pockets in its western balancing area. The five-year term of the PTP contract
1204 discouraged potential competing transmission requests that had potential to force
1205 even longer term transmission service agreement viewed as necessary to serve
1206 load. Any view of used and useful must recognize the commercial reality that the
1207 contract would have been difficult or risky to obtain for a period of less than five
1208 years. Because the contract was unavailable on a year-by-year basis, it should not
1209 be evaluated in that manner for ratemaking purposes.

1210 **Q. Why has the Company not entered into additional long-term power**
1211 **purchases that could take advantage of this PTP contract?**

1212 A. Other resources, primarily Chehalis with its own transmission rights to the
1213 Company system, have now replaced the Centralia resource and transmission
1214 rights.

1215 **Q. What would have been the consequences had the Company not entered into**
1216 **the five year Centralia PTP wheeling contract?**

1217 A. The Company believed it was at risk of having unserved load and estimated the
1218 cost at \$153 million, which is significantly more than the cost of the Centralia
1219 PTP wheeling contract over its entire term. Confidential Exhibit RMP___(GND-
1220 4R) provides support for the Company's decision.

1221 **Q. How do you respond to UIEC's argument that all but the redirected portion**
1222 **of the contract should be excluded from NPC?**

1223 A. For the reasons I discuss above, the Company's decision to enter into the

1224 Centralia PTP wheeling contract was prudent and has provided benefits to
1225 customers. There is no basis for disallowing a prudent contract that continues to
1226 be used and useful.

1227 **BPA/Idaho Power Rate Increase (OCS Adjustment 12)**

1228 **Q. What is OCS’s adjustment related to the BPA and Idaho Power Company**
1229 **(“Idaho Power”) rate increases?**

1230 A. OCS removes the changes to the BPA charges for wind integration and reserves,
1231 and the change to Idaho Power transmission rate. This adjustment reduces total
1232 Company NPC by \$2.2 million, the vast majority of which is attributable to the
1233 Idaho Power transmission rate increase. OCS also argues that NPC should not be
1234 updated to reflect a change in the BPA transmission rate in the event
1235 circumstances change and the rate changes.

1236 **Q. What is OCS’s argument in favor of removing these expected rate increases?**

1237 A. OCS claims that the increases are not known and measurable and should not be
1238 allowed unless final decisions on the rates are rendered prior to the hearing in this
1239 case.

1240 **Q. What are the rates that the Company included in its direct case for both the**
1241 **Idaho Power and BPA?**

1242 A. Based on the historical wheeling expenses for the period ended June 2010, the
1243 Company included the Idaho Power transmission rate that would be effective
1244 during the test period. The rate that Mr. Falkenberg referenced as a “change” was
1245 the known new rate that the Company was charged by Idaho Power beginning in
1246 October 2010 and is currently being charged.

1247 For the expected BPA rates, as I explained in my direct testimony, the
1248 current BPA rate cases are to determine the new rates for its next fiscal period and
1249 the Company included the best information available for the rate changes. BPA
1250 has issued a draft Record of Decision (“ROD”) on June 15, 2011. However, the
1251 draft ROD does not provide any useful information regarding how the new rates
1252 would change from the previous expectation. BPA is expected to issue its final
1253 ROD in July, and the Company will seek to incorporate the new information
1254 when available.

1255 **Q. Mr. Falkenberg states that the Commission denied a request to incorporate a**
1256 **wheeling rate increase into the test year in the Company’s 2009 GRC. Did**
1257 **the Commission reject the wheeling rate increase on the basis proposed by**
1258 **OCS in this case?**

1259 A. No. The Commission rejected the Company’s adjustment in that case because it
1260 was presented in rebuttal and related to an old and relatively complex contract.
1261 The Commission felt that parties did not have sufficient time to conduct discovery
1262 or evaluate the proposed changes. In this case, the actual rate increase of Idaho
1263 Power and expected rate increases of BPA were reflected in the Company’s direct
1264 case, so there is no question that parties have had time to evaluate and respond to
1265 the adjustment. Moreover, any change to the BPA transmission rate would be
1266 documented in BPA’s ROD, and any changes to either the Idaho Power’s or
1267 BPA’s rates would be documented on an invoice and/or on the utilities’ Open
1268 Access Same-Time Information System (“OASIS”). These documents are
1269 straightforward, objective, and easily verifiable.

1270 **Q. Are these contract changes similar to the BPA Peaking and Grant County**
1271 **contracts, for which the Commission accepted updated contract prices in the**
1272 **2009 GRC?**

1273 A. Yes. In the 2009 GRC, the Commission allowed the Company to incorporate
1274 changes to those contracts because this allowed the Commission to use the best
1275 information available and the changes were identified in the direct testimony,
1276 even though the exact quantification of the change was not available until later in
1277 the case.

1278 **Q. How do you respond to OCS's statement that if the Commission allows the**
1279 **Company to recover pending BPA rate increases, it should also increase**
1280 **wheeling revenues to reflect the Company's May 2011 proposed increase to**
1281 **transmission revenues?**

1282 A. The Company filed its wholesale rate case with FERC on May 26, 2011. At this
1283 time, the Company cannot anticipate the timing of the FERC decision and the
1284 subsequent effective date for the approved rates. However, as discussed in Mr.
1285 Steven McDougal's rebuttal testimony, the Company agrees that any changes in
1286 wheeling revenues associated with the FERC rate case will be deferred until the
1287 next rate case or otherwise reflected in the EBA since the Commission ordered
1288 wheeling revenues to be included in the EBA.

1289 **Transmission Imbalance Normalization (OCS Adjustment 12)**

1290 **Q. What is OCS's transmission imbalance adjustment?**

1291 A. OCS proposes to remove from total NPC \$0.3 million in penalties the Company
1292 has paid for unauthorized use of third party transmission resources. OCS claims

1293 that the Company removed \$0.4 million in wheeling revenue resulting from
1294 penalties for third parties being out of balance on the Company's transmission
1295 system, so it should also remove penalties the Company paid for transmission
1296 imbalances.

1297 **Q. Has OCS presented any basis for the Commission to depart from its holding**
1298 **in the 2009 GRC that the Company's exclusion of a transmission imbalance**
1299 **service adjustment is appropriate?**

1300 A. No. Mr. Falkenberg does not respond to my direct testimony on this issue, nor
1301 does he provide a basis for finding that a transmission imbalance adjustment was
1302 not appropriate in the 2009 GRC but is now appropriate. Instead he shifts the
1303 focus of his adjustment to the penalties the Company paid for transmission
1304 imbalances.

1305 **Q. Why is it appropriate to include in NPC transmission imbalance penalties**
1306 **paid by the Company?**

1307 A. Transmission imbalance penalties paid by the Company to third parties are
1308 normal, ongoing expenses that are incurred when the Company wheels on third
1309 party transmission systems. These expenses arise when the Company's actual
1310 deliveries of power over the course of an hour do not exactly match the schedule.
1311 The Company makes every effort to match the actual deliveries with the schedule
1312 of deliveries, but it is inevitable that the actual and scheduled deliveries may not
1313 match every hour of the year. The payments for such deviations are legitimate and
1314 real expenses of operating the Company's system and should remain in NPC.

1315 **Q. Why is it appropriate to exclude the revenue for transmission imbalances**
1316 **received by the Company?**

1317 A. Revenues for transmission imbalance received by the Company come from third
1318 parties that wheel on the Company's transmission system. Pursuant to FERC
1319 Order 890, the Company is required to distribute any imbalance payment received
1320 from the offending wheeling customers to the non-offending wheeling customers
1321 with no effect on retail customers.

1322 **Q. What do you conclude about the payments that the Company makes to third**
1323 **parties and the revenues that the Company collects from third parties?**

1324 A. They are completely different issues and should not be considered together.
1325 Imbalance expenses that the Company pays as part of the wheeling expenses are
1326 real expenses the Company pays third parties. Imbalance revenues that the
1327 Company collects as part of the other revenues are from third parties and refunded
1328 to other wholesale customers, leaving a net impact on retail customers of zero.
1329 The Commission should reject this adjustment because the Company treatment of
1330 imbalance revenues and expenses is appropriate.

1331 **Contract Adjustments**

1332 **Morgan Stanley Call Options (DPU Adjustment 8 and UIEC Adjustment 4)**

1333 **Q. Please explain DPU's and UIEC's proposed adjustments related to Morgan**
1334 **Stanley call option contracts.**

1335 A. DPU and UIEC propose to remove the capacity payments related to two of the
1336 Company's call option contracts because they claim the contracts were not likely

1337 to provide a benefit to customers. The adjustment would reduce the Company's
1338 system NPC by \$2.1 million.

1339 **Q. Do the Morgan Stanley call option contracts provide benefits to customers?**

1340 A. Yes. The benefit of these contracts has nothing to do with whether they are
1341 dispatched in GRID. The benefit of these contracts was addressed in the 2004 IRP
1342 and the 2004 IRP Update where it showed a present value revenue requirement
1343 benefit of \$639 million as a result of displacing new generating resources with up
1344 to 1,200 MW of Front Office Transactions ("FOTs").¹⁵

1345 **Q. When did the Company purchase the [REDACTED] of FOTs from Morgan
1346 Stanley?**

1347 A. The Company purchased the FOTs from Morgan Stanley on November 9, 2005,
1348 shortly after filing the 2004 IRP Update on November 3, 2005. The 2004 IRP
1349 Update confirmed the need to acquire up to 1,200 MW of FOTs that were
1350 identified in the preferred portfolio in the 2004 IRP.

1351 **Q. Why did the Company purchase these FOTs in November 2005 for delivery
1352 in the summer of 2011?**

1353 A. The preferred portfolio identified the need to purchase up to 700 MW of FOTs for
1354 2011 from markets on the east side of the system. Purchasing [REDACTED] in
1355 November 2005 was a means of stepping into this need since the Company cannot
1356 predict if prices would go higher or lower and wanted to spread out the price risk
1357 over time. The delivery point of these FOTs is [REDACTED], which is a relatively illiquid

¹⁵See page 172 of the 2004 Integrated Resource Plan;
http://www.pacificorp.com/content/dam/pacificorp/doc/Environment/Environmental_Concerns/Integrated_Resource_Planning_14.pdf.

1358 market. Purchasing these FOTs was reasonable based on the information available
1359 to the Company in November 2005.

1360 **Q. What alternatives were available to the Company to fill the FOT**
1361 **requirement identified in the preferred portfolio?**

1362 A. The Company could have waited to begin filling this need, hoping for a lower
1363 price, but as described above, the price could as easily have gone up and the
1364 Company is not able to predict where prices will go. Filling a portion of the need
1365 right after the plan was finalized was a prudent course of action.

1366 The other option would have been to enter into purchase power contracts
1367 to meet the identified need at then current market prices for 2011, which at that
1368 time was over [REDACTED]. If the call option contracts are removed from NPC, then
1369 they would need to be replaced by fixed price purchase power contracts using the
1370 November 2005 prices. This would likely increase NPC because it would
1371 probably be less expensive to pay current market prices and the call premiums
1372 than it would have been to pay over [REDACTED] for the power. The call premiums
1373 represent approximately [REDACTED] when spread out over the number of
1374 megawatt-hours of delivery under the contracts. As long as the Company can
1375 secure super peak power for less than [REDACTED] for June, July, and August of
1376 2011, then customers will pay less than they would have if the Company had
1377 secured power purchase contracts.

1378 **Q. UIEC claims that there was not a reasonable probability at the time the**
1379 **Company entered into the contract that customers would benefit from the**
1380 **contracts. Do you agree?**

1381 A. No. As described above, customer benefits were identified in the 2004 IRP and
1382 were significant. In addition, it is likely that the use of call options rather than
1383 purchased power agreements will further benefit customers.

1384 **Q. Did UIEC witness Mr. Widmer file testimony with the Utah Commission on**
1385 **behalf of the Company that is relevant to assessing what the Company knew**
1386 **or should have known about wholesale market projections when it executed**
1387 **the Morgan Stanley call options in November 2005?**

1388 A. Yes. In that same month, November 2005, Mr. Widmer filed testimony
1389 supporting the Company's request for a Power Cost Adjustment Mechanism. In
1390 that testimony, Mr. Widmer pointed to a dramatic "increase in wholesale markets
1391 and price volatility." When asked about the expected trend for the wholesale
1392 market price of electricity, Mr. Widmer testified that "prices are expected to stay
1393 high by historic standards and there will be some level of year-to-year volatility in
1394 wholesale market prices." This testimony shows that the Company's decision to
1395 acquire the call options was a reasonable and prudent response to protect
1396 customers from the risk of then-projected market conditions.¹⁶

1397 **Q. Did the Commission address the same issue in the Company's 2007 GRC?**

1398 A. Yes. In that case, parties proposed similar adjustments to several call option
1399 contracts. In its order, the Commission removed uneconomic dispatch of call

¹⁶ *Re the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulation*, Docket No. 05-035-102, Direct Testimony of Mark Widmer at 3-4 (November 2005). (See Exhibit RMP____(GND-5R).

1400 options, but left the capacity payments in the Company's NPC.¹⁷ In the current
1401 proceeding, the Company performed the same check of all the call options and
1402 removed the energy and expenses if exercising the call option is uneconomic. The
1403 Company's treatment of call option contracts in this case is therefore consistent
1404 with the Commission's 2007 GRC order.

1405 **Q. What would you recommend the Commission do in the current case?**

1406 A. The Commission should reject DPU's and UIEC's proposal to remove the
1407 capacity payment of the call option contracts for the reasons described above.

1408 **Black Hills and UMPA II Shaping (OCS Adjustment 4 and UIEC Adjustment 6)**

1409 **Q. What are the adjustments that OCS and UIEC propose to the modeling of**
1410 **the Black Hills and UMPA II sales contracts?**

1411 A. OCS and UIEC propose to substitute actual data for normalized data for the sales
1412 contracts with Black Hills Power ("Black Hills"). Their adjustments would result
1413 in a \$0.6 million or \$0.8 million reduction to system NPC, respectively. OCS also
1414 proposes a similar adjustment to the contract with the Utah Municipal Power
1415 Agency II ("UMPA II"). This adjustment would result in a \$0.2 million reduction
1416 to NPC.

1417 **Q. What are OCS's and UIEC's objections to the Company's modeling of these**
1418 **contracts?**

1419 A. OCS does not provide detailed objections, but merely refer to the Commission
1420 ordered modeling for the SMUD contract and what the Idaho Public Utilities
1421 Commission decided. UIEC argues that GRID assumes the counterparty finds the

¹⁷ *Re the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations*, Docket 07-035-93, Report and Order on Revenue Requirement at 23 (Aug. 11, 2008).

1422 most costly delivery pattern possible under the contract, and this modeling is not
1423 realistic. Based on Mr. Falkenberg's testimony in other proceedings, I understand
1424 his argument to be based on his belief that counterparties are not using the same
1425 forward price curves as the Company and have differences in delivery locations,
1426 transmission constraints, availability of the counterparties' own generation, and
1427 other factors that drive decisions regarding use of the available energy.

1428 **Q. Do you agree with that characterization?**

1429 A. No. The factors cited by Mr. Falkenberg provide no reasonable justification for
1430 modeling sales and purchase contracts differently. One could argue that those
1431 factors cited by Mr. Falkenberg would be unlikely to be the same between the
1432 historical period and the rate effective period or the test period, and it would be
1433 incorrect to state that the future would be the same as the history. GRID cannot
1434 predict with certainty what conditions will exist during the rate effective period
1435 that will impact either sales and purchase contracts. What is known is that the
1436 conditions in the past will not be the same as the conditions in the future. For
1437 purposes of forecasting, the logical course of action is to utilize known
1438 information, including the flexibility of the contracts, and use GRID to optimize
1439 sales contracts as it is used to optimize purchase contracts.

1440 **Q. Is the Company's modeling of these sales contracts consistent with its**
1441 **modeling of purchase contracts?**

1442 A. Yes.

1443 **Q. Why is it important to treat third-party contracts the same whether the**
1444 **Company is selling or purchasing energy?**

1445 A. Use of actual delivery patterns rather than optimized delivery patterns will always
1446 lower net power costs for wholesale sales contracts such as the Black Hills and
1447 UMPA II contracts. The opposite is true for purchased power contracts that give
1448 the Company flexibility in how the power is taken. It is not fair or consistent to
1449 normalize different contracts using different rules.

1450 **Q, Should the fact that the Commission found that actual data should be used**
1451 **for the SMUD contract have any bearing on how the Black Hills and UMPA**
1452 **II contracts are modeled?**

1453 A. No. The Black Hills and UMPA II contracts were in NPC when the Commission
1454 decided that the SMUD contract normalization should reflect actual deliveries. No
1455 adjustment to the Black Hills and UMPA II contracts were made concurrent with
1456 the adjustment to the SMUD contract then and should not be made now.

1457 **Q. UIEC argues that the Company uses actual information to model other**
1458 **contracts, so it is reasonable to model the Black Hills contract with actual**
1459 **information. How do you respond?**

1460 A. It is inappropriate to use the Company's modeling of non-flexible contracts such
1461 as the GEM State contract to justify its adjustments to the call option sales
1462 contracts. This contract does not provide the Company the kind of flexibilities
1463 that are provided for in the terms of the call option sales contracts. Based on the
1464 principal of known and measurable information, the only thing known to the
1465 Company is the history of those contracts.

1466 **Evergreen Contract (OCS Adjustment 6)**

1467 **Q. What does OCS propose with respect to the Evergreen contract?**

1468 A. OCS proposes that the actual deliveries for November 2007 through December
1469 2010 be used to compute the annual energy deliveries under the contract to
1470 account for the fact the facility did not come on line until 2007 and there is not
1471 sufficient data to compute normalized generation on a 48-month basis. The
1472 adjustment would decrease NPC by \$0.2 million on a total Company basis.

1473 **Q. Did OCS propose this methodology consistently across all contracts?**

1474 A. No. The DC Forest Products contract also uses contract estimates for the two
1475 months in the historical period for which the Company does not have actual data.

1476 **Q. Is OCS's proposal appropriate?**

1477 A. No. The Company uses a similar methodology for calculating forced outages for
1478 new generating units. It would be inappropriate to use actual data to calculate
1479 energy deliveries under a new contract, but not use actual data to calculate forced
1480 outages for new generating units.

1481 **Q. Please explain how the methodology for calculating forced outages for new**
1482 **generating units is similar to the Company's methodology for estimating**
1483 **energy under the Evergreen contract.**

1484 A. For new generating units, the Company uses the manufacturer's model specific
1485 fleet availability average to set the forced outage rate for the first year. Thereafter,
1486 the Company phases actual operating data into the calculation as it becomes
1487 available. Mr. Falkenberg recently supported this methodology in Oregon Docket
1488 UM 1355.

1489 Similarly, for the Evergreen contract, the Company uses the 32 months of
1490 actual data it has available for the contract November 2007 through June 2010.
1491 For the 16 months the Company does not have actual data, July 2006 through
1492 October 2007, the Company uses the generation estimate contained in the
1493 contract.

1494 **APS Daily Screening Adjustment (OCS Adjustment 6)**

1495 **Q. What adjustment has OCS proposed with respect to the APS Supplemental**
1496 **contract deliveries?**

1497 A. OCS proposes to use a daily screen to restrict the APS Supplemental contract
1498 deliveries. This adjustment reduced total Company NPC by \$0.2 million.

1499 **Q. Is using a daily screen for this contract appropriate?**

1500 A. No. OCS's does not provide any evidence in testimony to support their proposal.
1501 In fact, they dedicate two sentences to this adjustment without any empirical
1502 support as to its accuracy.

1503 **Q. Why does the Company apply the screen on monthly basis?**

1504 A. The Company applied the monthly screens to be consistent with the methodology
1505 authorized by the Commission in the Company's 2007 GRC for screening call
1506 option contracts.

1507 **Transmission Adjustments**

1508 **Short-Term Firm Transmission (UIEC Adjustment 5)**

1509 **Q. What is UIEC's adjustment to the modeling of short-term firm transmission?**

1510 A. UIEC lowered the threshold for transmission links to be included in the
1511 calculation of short-term transmission to 0.2 average MW from one average MW.

1512 UIEC's proposal would reduce total Company NPC by \$0.1 million.

1513 **Q. Do you have any general comments about this proposed adjustment?**

1514 A. Yes. The size of the threshold for short-term transmission in the Company's
1515 proposal was the same as proposed by Mr. Widmer when he was the witness on
1516 behalf of the Company. In this case, Mr. Widmer is essentially rejecting his own
1517 proposal by changing how it works without any support except to state that his
1518 adjustment would incorporate most of the transmission capability.

1519 **Q. Is UIEC's proposal appropriate?**

1520 A. No. UIEC has not demonstrated that the Company's current approach results in an
1521 inaccurate forecast of short-term transmission, and, therefore, should be rejected.
1522 UIEC's approach simply adds complexity to the model and reduces NPC without
1523 providing any additional accuracy.

1524 **Non-Firm Transmission (OCS Adjustment 11)**

1525 **Q. Please explain OCS's adjustment to NF transmission.**

1526 A. OCS proposes to model NF transmission capacity and costs on a volumetric basis
1527 using a 48-month average. This adjustment would reduce system NPC by \$2.1
1528 million.

1529 **Q. Why did the Company change its modeling of NF transmission in the current**
1530 **filing?**

1531 A. As I discussed in my direct testimony, while reviewing the modeling of STF and
1532 NF transmission in order to provide the explanation required by the Commission
1533 in the 2009 GRC, the Company determined that it purchases and uses NF and

1534 STF transmission in the same way. Based on this finding, the Company found no
1535 reasonable basis for modeling the two types of transmission differently.

1536 **Q. Is GRID able to capture all of the costs associated with NF transmission**
1537 **using the volumetric method supported by Mr. Falkenberg?**

1538 A. No. GRID's topology cannot capture wheeling expenses for transmission that is
1539 within a transmission area. In the process of reviewing how the Company utilizes
1540 NF transmission and the historical costs, it was clear that GRID was not able to
1541 fully capture not only the way in which the Company utilizes NF transmission,
1542 but also the costs associated with it. This new information justifies changing the
1543 manner in which the Company models NF transmission from the previous
1544 Commission findings on this subject.

1545 **Q. Does the Company use NF transmission solely for economic purposes, as**
1546 **claimed by OCS?**

1547 A. No. The Company utilizes NF transmission to balance its system and serve its
1548 load obligations, and in a manner that takes into consideration various events,
1549 including supporting generation and transmission forced outages and serving load.
1550 GRID cannot capture the use of NF transmission for these purposes and cannot
1551 accurately model the costs of NF transmission on a volumetric basis.

1552 **Q. OCS also argues that the prior modeling did a better job of replicating the**
1553 **real time situation where operators decide whether to make a purchase of NF**
1554 **transmission in the coming hours. How do you respond?**

1555 A. For the reasons already discussed, NF transmission is only purchased when STF
1556 transmission is not available, and when it is purchased it is purchased in the same

1557 manner as how the STF transmission is purchased.

1558 **Q. Is OCS's claim valid that the Company's method cannot readily demonstrate**
1559 **any linkage between the NF capacity costs it is including in the test year with**
1560 **any of the capacity links it is modeling?**

1561 A. No. OCS's claim assumes that the purchase of NF transmission is somehow
1562 different than STF transmission. It is not. NF transmission is purchased on the
1563 same basis as STF transmission when STF transmission is not available. OCS's
1564 proposal to treat NF transmission differently from STF transmission is
1565 unreasonable and should be rejected.

1566 **Transmission Line Loss Adjustment (OCS Adjustment 13)**

1567 **Q. Please describe the line loss adjustment proposed by OCS witness Ms.**
1568 **Ramas.**

1569 A. Ms. Ramas proposed a change in the Company's line loss calculation that
1570 incorporates calendar year 2010 data, and changes the basis of the calculation
1571 from a five-year (2005-2009) to a three-year (2008-2010) average.

1572 **Q. How does the Company use the line loss calculations in preparing a general**
1573 **rate case?**

1574 A. Line losses are a component of the load forecast, which affects many elements of
1575 the Company's overall revenue requirement. As explained by Company witness
1576 Dr. Peter Eelkema, the sales and load forecast is the primary driver in developing
1577 the Company's net power costs, jurisdictional allocation factors among the states,
1578 and forecasted sales and revenues by customer class.¹⁸

¹⁸ See Eelkema Direct Testimony at 2-3.

1579 **Q. Was calendar year 2010 line loss data available at the time the Company**
1580 **prepared its filing?**

1581 A. No. The Company filed its rate case on January 24, 2011. The most recent load
1582 forecast available at the time the Company prepared its Utah general rate case was
1583 completed in October 2010 when 2010 line loss data was not final and not yet
1584 available.

1585 **Q. Can you estimate what portion of Ms. Ramas' adjustment is attributable to**
1586 **the update in the time period and what portion is attributable to the change**
1587 **from the five-year average to the three-year average?**

1588 A. Yes. Approximately 75 percent of the proposed adjustment is attributable to the
1589 updating of the time period from 2005-2009 to 2006-2010, and approximately 25
1590 percent of the proposed adjustment is attributable to the change from the five-year
1591 average of 2006-2010 to the three-year average of 2008-2010.

1592 **Q. Did Ms. Ramas update any other components in the load forecast other than**
1593 **line losses?**

1594 A. No. Ms. Ramas updated only one of the many components that go into the load
1595 forecast, such as industrial sales, monthly peak forecasts, economic drivers,
1596 industrial customer usage, weather, customer class data, and usage per-day. Ms.
1597 Ramas selectively used only the most recent information with regard to line
1598 losses, and did not propose that the total load forecast be updated with more
1599 current information.

1600 **Q. Is it reasonable to update only line losses in the load forecast, and not update**
1601 **all of the components that are used to calculate the load forecast?**

1602 A. No. Updating only one component of the load forecast is a one-sided adjustment
1603 that does not take into consideration several other components that drive the load
1604 forecast.

1605 **Q. How is updating the load forecast different than updating the OFPC?**

1606 A. Updating the OFPC is much simpler and more transparent than updating the load
1607 forecast. The OFPC can be updated in a day and can be easily validated, while it
1608 takes months to update the load forecast due to the need to gather new
1609 information from large customers, add new load research data, update economic
1610 factors, add new historic load data, update losses, and update model coefficients
1611 for the monthly energy, peak and hourly models. In addition, a new load forecast
1612 would require recalculating revenues, allocation factors and NPC.

1613 **Q. Recognizing the Company's objection to updating the line loss calculation**
1614 **with new information, and not all components of the load forecast, does the**
1615 **Company also object to Ms. Ramas's proposal to change from a five-year to**
1616 **a three-year average?**

1617 A. Yes. Ms. Ramas suggests that there is an underlying trend in the line loss
1618 calculation since 2003 that suggests that a three-year average would be more
1619 appropriate.

1620 **Q. Does the Company believe that a five-year average is a reasonable measure**
1621 **of line losses?**

1622 A. Yes. A five-year time period achieves a reasonable balance between choosing a

1623 time period that is long enough to reduce volatility, but not so long that the
1624 average is based on stale data.

1625 **Q. Do you agree with Ms. Ramas, that there is a trend in the data that is better**
1626 **captured using a three-year versus a five-year average?**

1627 A. No. In the past ten years, as shown in Exhibit OCS 3.23.1, Utah line losses have
1628 varied from year-to-year and do not have a measurable downward trend.
1629 Changing the line loss calculation from a five-year to a three-year average has no
1630 basis in fact and will cause greater volatility in the load forecast thereby
1631 decreasing the stability of the forecast from year-to-year.

1632 **Q. What is a reasonable tool to use in the determination of the line loss time**
1633 **period?**

1634 A. The Company does not disagree with Ms. Ramas' choice of Mean Absolute
1635 Percentage Error ("MAPE") as the tool; however, the Company objects to the
1636 application of the MAPE.

1637 **Q. Please discuss further Ms. Ramas's application of the MAPE.**

1638 A. Ms. Ramas's Exhibit OCS 3.24.1, shows a decrease in the MAPE for a three-year
1639 versus a five-year average of 0.2 percent for Utah over a six year period, and an
1640 overall system decrease in MAPE of only 0.6 percent. This is the basis for Ms.
1641 Ramas's claims of increased accuracy. What Ms. Ramas does not show is that
1642 when looking at the MAPE statistics for all seven regions individually, which is a
1643 better representation of how the SE allocation factor is calculated, it shows
1644 significant increases in MAPE in California (4.34 percent) and Western Wyoming
1645 (13.37 percent), and a minimal increase in Idaho (0.88 percent).

1646 **Q. Is it reasonable to draw a conclusion of increased accuracy when reviewing**
1647 **an historical period that encompasses only 6 years?**

1648 A. No. Utilizing only 6 data points in which to compare a three-year versus a five-
1649 year average, is not reasonable to claim that the forecast would be “more
1650 accurate” on a consistent basis going forward.

1651 **Q. Has OCS recently reviewed and opined on the Company’s use of a five-year**
1652 **average when calculating line losses for use in its load forecast?**

1653 A. Yes. In June, 2009, OCS filed a comprehensive report by GDS Associates, Inc
1654 (“GDS”), in their comments on the 2008 IRP (Section 3.1.4), to examine the
1655 Company’s load forecast. In this report, GDS made the following comments on
1656 the Company’s line loss calculation:

1657 The Company used a five-year average of line loss percentages
1658 as the forecasted line loss factor. This methodology is sound in
1659 the absence of any specific knowledge of operational or system
1660 changes that might impact losses (such as implementation of
1661 AMI, accounting changes, or changing out old wire). GDS often
1662 uses a five-year average line loss factor when preparing forecasts
1663 for its clients.

1664 **Q. Has Ms. Ramas provided any reason for why circumstances have changed**
1665 **since June, 2009, at which time OCS concurred with the GDS on the**
1666 **Company’s methodology, that would lead the Commission to conclude that a**
1667 **three-year average is more reasonable than a five-year average?**

1668 A. No. Ms. Ramas has failed to comment on any operational or system changes that
1669 impact line losses from year-to-year on the Company’s system. Ms. Ramas
1670 simply claims there is a downward trend and that a three-year average is lower
1671 than a five-year average.

1672 **Q. Did OCS indicate the clients that GDS uses a 5-year average line loss factor**
1673 **for line losses?**

1674 A. No. The Company asked, but OCS refused to provide the names of the clients or
1675 any information as to the number of clients for whom GDS recommended the use
1676 of five-year losses when preparing forecasts.

1677 **Q. Does changing from a five-year to a three-year average represent a**
1678 **significant departure from the current methodology?**

1679 A. Yes. If the Commission made this change it would be a policy decision that would
1680 have implications system-wide. The Company would need to further evaluate and
1681 take into consideration the implications this change may have on any individual
1682 state, including Utah, not only in the current GRC proceedings, but all filings in
1683 which the load forecast is used in all six states.

1684 **Public Service of New Mexico LF Transmission Contract (OCS Adjustment 14)**

1685 **Q. What is OCS's adjustment based on the Public Service New Mexico long**
1686 **term firm transmission contract?**

1687 A. OCS argues that the Company includes the cost of this contract in the test year,
1688 but does not include the capacity of the link. OCS includes the link in the GRID
1689 model and proposes a \$0.6 million reduction to NPC.

1690 **Q. Is OCS correct that the Company does not include the capacity of the link in**
1691 **GRID?**

1692 A. Yes. The Company does not include the capacity of a link between COB and Four
1693 Corners because the contract with the City of Redding does not deliver energy

1694 from COB to Four Corners. It would be an error in the modeling to reflect a
1695 capacity link on behalf of this contract.

1696 **Q. Please explain how the contract, or as it is referred to in the model, the**
1697 **Redding Exchange contract, works.**

1698 A. Generation from the San Juan generation station is delivered to Four Corners,
1699 which the Company uses to serve load or make wholesale sales. The Company
1700 delivers power to Redding at COB, from its system in the west. San Juan is
1701 included in the Four Corner transmission area and there is no transfer of energy
1702 from COB to Four Corners as implied by Mr. Falkenberg. Mr. Falkenberg's
1703 adjustment is based on an apparent misunderstanding of the contract.

1704 **Outage Related Adjustments**

1705 **Thermal Fleet Outage Rate (OCS Adjustment 21 and UIEC Adjustment 13)**

1706 **Q. Please describe the adjustments OCS and UIEC proposes to make to the**
1707 **Company thermal fleet.**

1708 A. Mr. Falkenberg makes a number of adjustments to the Company's thermal fleet
1709 including increasing the availability of Lake Side, Colstrip 4, Naughton 3, Cholla
1710 4, and the entire Jim Bridger plant. Mr. Widmer also proposes increasing the
1711 availability of Naughton 3. In addition, Mr. Falkenberg and Mr. Evans bias heat
1712 rates to create artificial efficiencies that are not physically possible to capture. All
1713 of these adjustments reduce NPC.

1714 **Q. How does the performance of the Company's thermal fleet compare to its**
1715 **peer group?**

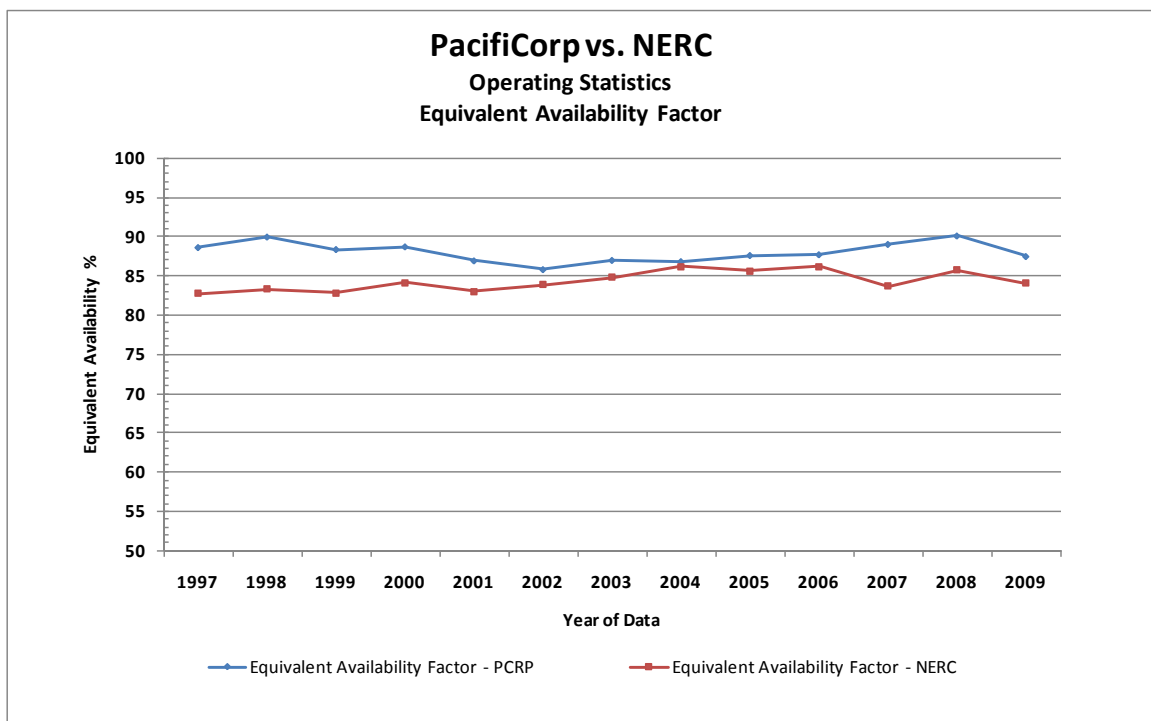
1716 A. There are two important statistics that can explain how the Company's thermal

1717 fleet compares to its peer group: equivalent availability and capacity factor.

1718 **Q. Why is equivalent availability an important statistic when comparing plant**
1719 **performance?**

1720 A. Equivalent availability is a measure of the optimal energy that could have been
1721 generated during a given report period. This eliminates the bias of market
1722 conditions. As Figure 1 below illustrates, the Company’s fleet consistently has a
1723 greater equivalent availability factor than its North American Electric Reliability
1724 Corporation/Generating Availability Data System (“NERC/GADS”) peer group.

1725 **Figure 1: Historical Equivalent Availability Factors**



1726 Equivalent availability also takes into account all the reasons a plant could
1727 be off-line, including planned outages, planned derates, forced outages,
1728 maintenance outages, equivalent forced derates, and equivalent maintenance
1729 derates. This means that the equivalent availability data removes the bias that can

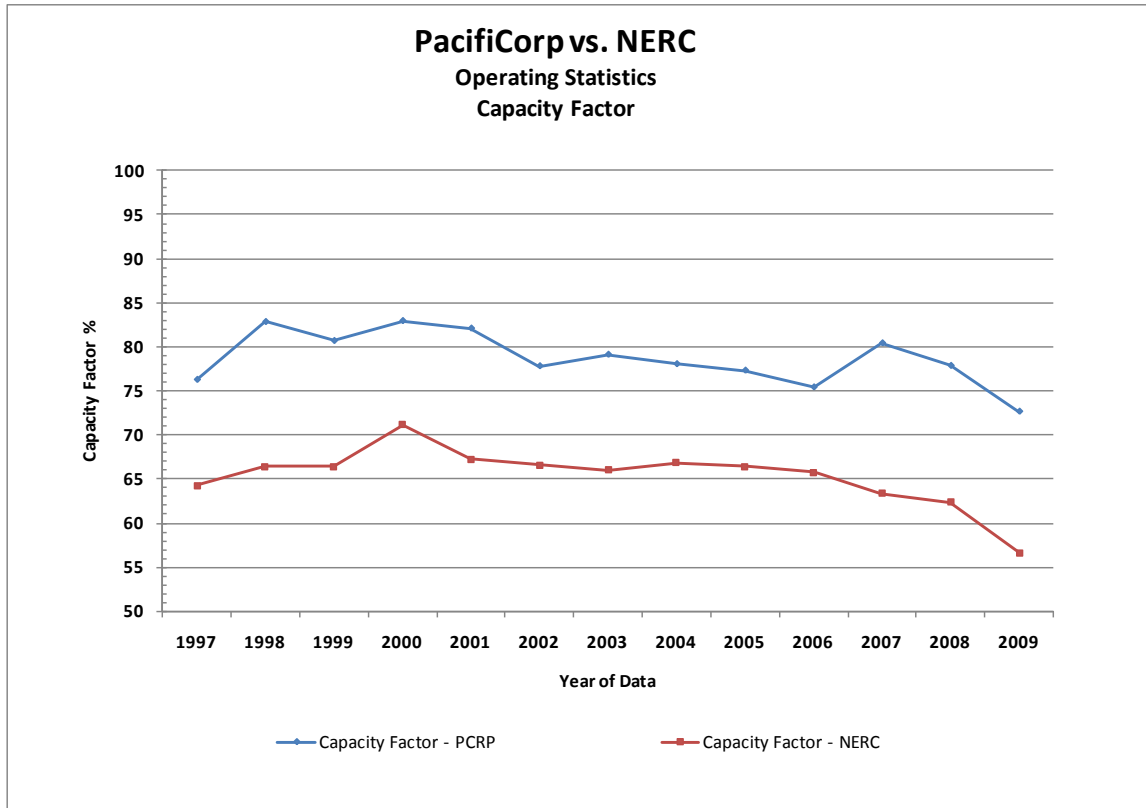
1730 appear if a Company outage is placed in a different category than a comparable
1731 outage from the NERC/GADS peer group. For example, it does not matter if an
1732 outage is classified as maintenance or forced; they are all treated equally in
1733 equivalent availability.

1734 The above graph also shows that the Company fleet is improving its
1735 performance against the NERC/GADS peer group over the last four years.

1736 **Q. Why should capacity factor be considered?**

1737 A. Capacity factor is the measure of actual output compared to the possible output.
1738 Therefore, the higher the capacity factor the more the plant has operated at or near
1739 its maximum capacity. Because this is the most efficient operating level, it means
1740 that power is produced at its lowest cost. It also means that the Company's fleet is
1741 able to generate more power thus offsetting the need for the Company to purchase
1742 power on the wholesale market. The Company fleet's capacity factor is
1743 consistently greater than the NERC/GADS peer group as illustrated in Figure 2
1744 below.

1745 **Figure 2: Historical Capacity Factors**



1746 By operating the fleet at these high capacity factors the Company is able
1747 to provide greater benefit to its customers by supplying a low cost source of
1748 energy.

1749 **Q. The Company's capacity factor for the four-year period ending December**
1750 **31, 2009, is 14.6 percent greater than the NERC/GADS peer group average.**
1751 **What is the approximate value associated with the Company's above-average**
1752 **capacity during this period?**

1753 **A.** The value of the power associated with the Company's fleet running above the
1754 NERC/GADS peer group capacity factor for the four-year period ending

1755 December 31, 2009, is in the range of \$200 million to \$300 million.¹⁹ These
1756 savings have helped the Company maintain relatively low NPC compared to other
1757 utilities.

1758 **Q. What do you conclude from these comparisons?**

1759 A. The Company is already operating its fleet above industry standards. OCS's and
1760 UIEC's adjustments to further increase plant availability by selective, ad hoc
1761 adjustments to specific unit outage rates unfairly ignores this overall level of
1762 performance and artificially decreases NPC.

1763 **Q. OCS proposes four adjustments to exclude certain outages from the four-**
1764 **year historic period. Is this proposal consistent with the Commission's**
1765 **adoption of the EBA?**

1766 A. No. The Commission's recent order approving an EBA for the Company stated
1767 that "the Company will not adjust Actual NPC for hydro conditions and forced
1768 outages because they give rise to the fluctuations the mechanism is designed to
1769 capture."²⁰ This indicates that the Commission intends for forced outage rates
1770 that are higher or lower than expected to be accounted for in the EBA.

1771 **Q. Has the Commission addressed whether long outages should be included in**
1772 **the calculation of the outage rate?**

1773 A. Yes, in the context of planned outages for Cholla Unit 4. In the Company's 2001
1774 GRC, DPU and OCS proposed excluding an unusually long outage that resulted
1775 from unanticipated problems during planned maintenance. The Commission

¹⁹ This estimate assumes roughly a \$20 to \$30/MWh savings associated with avoided market purchases due to the higher coal generation. The additional generation of 1,265 average megawatt or approximately 11 million megawatt-hours is 14.6 percent of the average fleet capacity of 8,676 average megawatt.

²⁰ *Re Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism*, Docket No. 09-035-15, Report and Order at 13 (Mar. 2, 2011).

1776 rejected the proposed adjustment, noting that maintenance data reveal that a large
1777 number of maintenance outages is not unusual and contain unexplained high and
1778 low numbers. The Commission found that the overall level of maintenance hours
1779 in the year of the Cholla outage was low, and therefore the inclusion of the outage
1780 “does not undermine our objective of obtaining a normal number of maintenance
1781 hours from this calculation.”²¹

1782 Similarly, forced outage data contains both unusually high outage rates
1783 and unusually low outage rates for various plants. Removing long outages while
1784 reflecting years in which outage rates are low undermines the objective of
1785 accurately reflecting expected forced outage rates in rates.

1786 **Q. Has Mr. Falkenberg previously proposed to include long forced outages in**
1787 **the calculation of forced outages?**

1788 A. Yes. Mr. Falkenberg testified on behalf of the Wyoming Industrial Energy
1789 Consumers (“WIEC”) in a case before the Wyoming Public Service Commission
1790 relating to the unusually long Hunter outage. The Commission characterized Mr.
1791 Falkenberg’s position in that case as follows:

1792 Regarding the proper calculation of thermal availability for the rate
1793 case, Falkenberg advocated allowing the Hunter No. 1 costs to
1794 become part of a four year rolling average of outage rates, as
1795 PacifiCorp had done in the past. *He found that method to be an*
1796 *effective, balanced and beneficial approach because it provided*
1797 *PacifiCorp with a reflection of outage impacts in rates while*
1798 *creating an incentive for PacifiCorp to minimize the cost and*
1799 *duration of outages.*

1800 Docket No. 20000-ER-02-184, Order ¶ 251 (March 6, 2003) (emphasis
1801 added).

²¹ *Re PacifiCorp d/b/a Utah Power & Light Co.*, Docket No. 01-135-01, Order (Sept. 10, 2001).

1802 The Company uses the same “effective, balanced and beneficial” approach
1803 advocated by Mr. Falkenberg in that case.

1804 **Lake Side and Colstrip 4 Outage Rate (OCS Adjustment 21)**

1805 **Q. With regard to the outages at Lake Side and Colstrip 4, how do you respond?**

1806 A. Mr. Falkenberg did not question the prudence of these outages, only that it is
1807 unrealistic to assume such extreme events will occur once every four years. I
1808 disagree. With a fleet of 40 individual thermal units, a four-year history creates an
1809 opportunity for over 160 years of unit-year operations. This could certainly result
1810 in outages longer than 28 days across the fleet as being normal. Mr. Falkenberg’s
1811 annual adjustments over the last several years for these “extreme events” is proof
1812 that they occur with more frequency than he has implied.

1813 **Naughton 3 Outage Rate (OCS Adjustment 21 and UIEC Adjustment 13)**

1814 **Q. Mr. Falkenberg and Mr. Widmer suggest that since the Company collected**
1815 **liquidated damages from Siemens, it should not be allowed to recover the**
1816 **costs associated with the lost energy due to an extended outage period. Do**
1817 **you agree?**

1818 A. No. The Company acted prudently with respect to the Naughton 3 outage. The
1819 Company prudently selected a contractor based on cost and outage length. The
1820 Company prudently negotiated a liquidated damages clause with the contractor
1821 before the start of repairs. The Company prudently exercised that clause when
1822 poor subcontractor performance negatively impacted outage completion. The
1823 collection of liquidated damages from the outage repair does not displace the need

1824 to reflect appropriate outage durations in the four-year average outage rate for the
1825 thermal unit in question.

1826 **Cholla 4 Outage Rate (OCS Adjustment 21)**

1827 **Q. How do you respond to Mr. Falkenberg's proposed adjustment to Cholla 4?**

1828 A. Mr. Falkenberg removes outages at Cholla 4 that occurred from July 2006
1829 through March 2008 on the claim that the Company fixed the plant and does not
1830 expect the problem to occur again. The data request cited, WIEC 12.9, does not
1831 make such a statement. The following is how the Company responded to WIEC
1832 12.9:

1833 From July 2006 to March 2008 Cholla Unit 4 recorded output
1834 restrictions due to steam path flow limitations. During the Spring
1835 2008 overhaul, the turbine original equipment manufacturer
1836 restored the steam path to original specifications, restoring full
1837 capacity. These overhaul costs are included in the four-year
1838 average generation overhaul expenses. The Company has not
1839 excluded such events in its determination of normalized outages.

1840 **Q. Has Mr. Falkenberg supported making an adjustment to outage rates when**
1841 **new capital investment may improve reliability?**

1842 A. No. To the contrary, Mr. Falkenberg testified on behalf of the Industrial
1843 Customers of Northwest Utilities (ICNU) in a case before the Oregon Public
1844 Utility Commission relating to a generic investigation into forecasting forced
1845 outage rates for electric generating units. In this proceeding Mr. Falkenberg made
1846 the following point:

1847 **Q. Should forced outage rate determinations be adjusted when new**
1848 **capital investment improves reliability?**

1849 A. As a general matter, only after these improvements have shown up
1850 in the historical data. Customers may be asked to pay for the

1851 investments as they are made, but not see the benefits for several
1852 years. While arguably inequitable, it opens up a “can of worms” to
1853 make ad-hoc adjustments to address the expected or assumed
1854 reliability benefits of new investment. Further, there are likely to be
1855 situations where new capital investment arguably degrades
1856 reliability. For example, pollution control equipment, such as
1857 scrubbers could result in reductions to plant availability. It would be
1858 unfair to adopt a policy that favors either reliability enhancement or
1859 reliability degradation, but not both. Further, quantifying the
1860 impacts of such reliability improvements or degradations would be
1861 quite subjective. For these reasons, there should be a prejudice
1862 against making ad-hoc adjustments to the computation of outage
1863 rates. *An advantage of a rolling average is that actual changes to*
1864 *plant reliability will be factored into the ratemaking process in due*
1865 *course.*²²

1866 The Company supports the use of the four-year rolling average approach
1867 advocated by Mr. Falkenberg in that case.

1868 **Bridger Outage Rate (OCS Adjustment 21)**

1869 **Q. With regard to Mr. Falkenberg’s adjustments to the Jim Bridger plant, how**
1870 **do you respond?**

1871 A. Mr. Falkenberg makes three adjustments to the Jim Bridger plant. I address the
1872 first of these adjustments related to outages that were associated with liquidated
1873 damage payments. Ms. Crane addresses the other two aspects of this
1874 adjustment—Bridger fines and fuel quality.

1875 **Q. Why is Mr. Falkenberg’s adjustment to the outages associated with**
1876 **liquidated damages payments incorrect?**

1877 A. Mr. Falkenberg associates liquidated damages with imprudence on behalf of the
1878 Company. This is an improper conclusion, because it is the contractor that pays
1879 liquidated damages to the Company. Mr. Falkenberg has provided no basis for the

²² *Re Pub. Util. Comm’n of Or. Investigation into Forecasting Forced Outage Rates for Electric Generating Units*, Direct Testimony and Exhibits of Randall J. Falkenberg, ICNU/100, Falkenberg/21 (Apr. 7, 2009) (emphasis added).

1880 Commission to conclude that the Jim Bridger outages were imprudent and subject
1881 to exclusion from the forced outage rate.

1882 **Q. What additional outage adjustments does Mr. Falkenberg make to the Jim**
1883 **Bridger plant?**

1884 A. Mr. Falkenberg claims that the Bridger facility has experienced a higher rate of
1885 outages and derations due to employee errors. He goes on to state that the
1886 employee error outage rate is more than twice the NERC average.

1887 **Q. Has Mr. Falkenberg cited any imprudence in these personnel error coded**
1888 **events?**

1889 A. No. Mr. Falkenberg's adjustment does not claim imprudence nor does it point out
1890 a lack of procedures or routines maintained by the Company that are intended to
1891 minimize human errors and maintain safe operations at the facility.

1892 **Q. Has the Company further reviewed Mr. Falkenberg's claims that the Jim**
1893 **Bridger facility was "responsible for more than 60 percent of all PacifiCorp**
1894 **lost energy due to employee errors..."?**

1895 A. Yes. After reviewing the Company's "human error events" over the past 10 years,
1896 the Company calculates that 24 percent of the total MWh lost due to human error
1897 coded events is attributable to the Jim Bridger facility, not 60 percent as claimed
1898 by Mr. Falkenberg. Jim Bridger represents approximately 23 percent of the total
1899 thermal capacity of the Company's fleet; therefore the magnitude of the
1900 percentage of human error codes is consistent with its size.

1901 **Q. Do you agree with Mr. Falkenberg’s claim that outage rate of the Jim**
1902 **Bridger facility is “more than twice the NERC average?”**

1903 A. No. In his calculation of the Jim Bridger coal unit lost MWh, Mr. Falkenberg used
1904 all of the NERC Personnel Error codes used by the Company, yet when he
1905 compared the Personnel Error code data to the NERC average he excluded two of
1906 those codes in his NERC comparison. The two codes he excluded from the
1907 comparison were codes showing zero lost energy for the Jim Bridger facility.
1908 Once those two codes are included in the NERC five-year average, the Jim
1909 Bridger facility is in line with the NERC average.

1910 **Q. Is it reasonable to exclude the two error codes from the NERC average?**

1911 A. No. The Personnel Error cause code category, as established by NERC, includes
1912 six personnel error codes: Operator Error, Maintenance Personnel Error,
1913 Contractor Error, Operating Procedure Error, Maintenance Procedure Error,
1914 Contractor Procedure Error, and Staff Shortage. The Company does not currently
1915 use Staff Shortage as an available error code. It is up to the individual reporting
1916 unit to interpret the type of Personnel Error code within that category that the
1917 outage fits into. An example of this type of subjective interpretation would be the
1918 use of Operator Procedure error versus Operator Error. Mr. Falkenberg’s
1919 exclusion of the two error codes that are reported as zeros at the Jim Bridger
1920 facility is a selective representation of the information and an inappropriate
1921 comparison.

1922 **Q. How does the Jim Bridger facility compare overall to the NERC average in**
 1923 **cause code categories?**

1924 **A.** Comparing NERC’s top 25 cause codes for years 2006-2009, coal-fired units 400-
 1925 599 MW, Jim Bridger is better than the NERC average in 19 of the 25 cause
 1926 codes categories. See Table 1 below:

Table 1

Rank	Cause Code	Description	Better than National Standard	Worse than National Standard
1		1 No Manufacturer Equipment	<input checked="" type="checkbox"/>	
2		1800 Major Boiler Overhaul (720 Hours or Longer)		<input checked="" type="checkbox"/>
3		1999 Boiler; Miscellaneous	<input checked="" type="checkbox"/>	
4		4400 Major Turbine Overhaul (720 Hours Or Longer)	<input checked="" type="checkbox"/>	
5		1000 Waterwall (furnace Wall)		<input checked="" type="checkbox"/>
6		1801 Minor Boiler Overhaul (less than 720 Hours)	<input checked="" type="checkbox"/>	
7		9690 Other Misc. Operational Environmental Limits - All	<input checked="" type="checkbox"/>	
8		1810 Other Boiler Inspections	<input checked="" type="checkbox"/>	
9		1060 First Reheater Leaks	<input checked="" type="checkbox"/>	
10		1050 Second Superheater Leaks		<input checked="" type="checkbox"/>
11		1040 First Superheater Leaks		<input checked="" type="checkbox"/>
12		3839 Other Auxiliary Steam Problems	<input checked="" type="checkbox"/>	
13		4520 Gen. Stator Windings; Bushings; And Terminals	<input checked="" type="checkbox"/>	
14		4014 Hp Turbine Bucket Or Blade Fouling		<input checked="" type="checkbox"/>
15		3440 High Pressure Heater Tube Leaks	<input checked="" type="checkbox"/>	
16		1493 Air Heater Fouling (Regenerative)		<input checked="" type="checkbox"/>
17		9510 Plant Modific. Strictly For Compliance W/ Reg. Req	<input checked="" type="checkbox"/>	
18		1812 Boiler Inspections - Scheduled or Routine	<input checked="" type="checkbox"/>	
19		1455 Induced Draft Fans	<input checked="" type="checkbox"/>	
20		260 Primary Air Fan	<input checked="" type="checkbox"/>	
21		8560 Electrostatic Precipitator Problems	<input checked="" type="checkbox"/>	
22		310 Pulverizer Mills	<input checked="" type="checkbox"/>	
23		1340 Tube Modifications (including Addition And Removal of Tubes)	<input checked="" type="checkbox"/>	
24		1090 Other Boiler Tube Leaks	<input checked="" type="checkbox"/>	
25		3410 Feedwater Pump	<input checked="" type="checkbox"/>	

1927 Personnel Error codes is not shown because it does not make NERC's top 25 in
1928 cause code categories. Mr. Falkenberg's adjustment, based on the Personnel Error
1929 code category, is based on a selective use of information that ignores the overall
1930 excellent performance of the facility.

1931 **Q. What is your overall conclusion regarding OCS's and UIEC's adjustments to**
1932 **the thermal fleet?**

1933 A. Based on the superior performance of the thermal fleet both from an availability
1934 and capacity factor basis, there is no valid reason to adopt any of the adjustments
1935 proposed by OCS and UIEC. These ad-hoc adjustments are selective, one-sided,
1936 and fail to recognize the excellent performance overall of the Company's fleet.

1937 **Heat Rate Modeling (DPU Adjustment 10 and OCS Adjustment 22)**

1938 **Q. How does the Company apply the deration method?**

1939 A. The Company's approach derates the maximum capacity of the unit in every hour
1940 of the year by an equal percent based on historic forced outage rates, which
1941 constitutes a "hair cut" in unit availability.

1942 **Q. Do DPU and OCS propose changes to the Company's deration method?**

1943 A. Yes. DPU's proposed modeling would result in a \$4.1 million decrease to system
1944 NPC, while OCS's proposed modeling would result in a \$1.4 million reduction.

1945 **Q. Do DPU and OCS propose the same methodology for altering the Company's**
1946 **heat rate deration method?**

1947 A. No.

1948 **Q. How would DPU's proposal change this method?**

1949 A. It is unclear how Mr. Evans reflected the adjustment in GRID. It seems that Mr.

1950 Evans included an adjustment equivalent to what OCS and UIEC made for
1951 reserve shutdowns. However, based on Mr. Evans's testimony, DPU's approach
1952 would alter thermal units' heat rate curves to artificially increase their efficiency
1953 as compared with the heat rate curves that are developed from actual plant
1954 operating data. This is essentially what Mr. Falkenberg has proposed in the past
1955 and has since given up.

1956 **Q. Why is DPU's proposal unreasonable?**

1957 A. As Mr. Falkenberg agreed with the Company that the only time when the derate
1958 adjustment to the heat rate may be applicable is when the unit is dispatched at one
1959 particular level of generation—its derated maximum capacity, with the
1960 assumption that the unit may be dispatched at its stated maximum capacity in
1961 GRID if there were not the availability "haircut." When the unit is dispatched at
1962 any level below its derated maximum capacity, GRID has made the optimal
1963 decision to dispatch that unit at a lower and less efficient generation level,
1964 whether it has been derated or not. Therefore, derating the entire heat rate curve
1965 overstates the efficiency of the unit and understates the heat inputs.

1966 **Q. In the current proceeding, OCS's proposed adjustment seems to be at the**
1967 **units' derate maximum. Would you agree with such adjustment based on**
1968 **your discussion above?**

1969 A. No. The Company uses the "haircut" to adjust down a unit's capacity that is still
1970 at a relatively efficient level. In actual operations, a unit can be derated to any
1971 level between its minimum and maximum capacities.

1972 **Q. OCS claims to illustrate the problem with the Company's outage rate**
1973 **modeling technique using Colstrip as an example. Do you agree that OCS's**
1974 **example shows that the Company's modeling of this issue is unreasonable?**

1975 A. No. OCS's example only addresses one point on the heat rate curve and fails to
1976 acknowledge that the remainder of the artificial heat rate curves generation by Mr.
1977 Falkenberg are incorrect.

1978 **Q. Are there other problems with OCS's adjustments?**

1979 A. Yes. In making his adjustment, Mr. Falkenberg assumed that the forced outages at
1980 the Company's gas-fired units are all full outages, which is far from accurate. As
1981 a matter of fact, as shown in the data that the Company has provided, derations
1982 represent about half of the historical lost generation for some gas-fired units.

1983 The Commission rejected similar adjustments in the 2009 GRC and there
1984 is no basis for reconsidering that outcome.

1985 **Reserve Shutdowns (OCS Adjustment 21 and UIEC Adjustment 2)**

1986 **Q. What are OCS's and UIEC's adjustments related to reserve shutdowns?**

1987 A. OCS claims that reserve shutdowns for coal plants seem unlikely now that market
1988 prices have increased and coal generation is necessary to provide reserves for
1989 wind integration. UIEC claims that the Company's calculation of forced outage
1990 rates is not consistent with how GRID uses the forced outage rates, because
1991 outage rates used as an input to GRID are calculated after reserve shutdowns,
1992 while GRID uses outage rates as if they are before reserve shutdowns. OCS and
1993 UIEC propose to remove reserve shutdowns from the calculation of the forced

1994 outage rate. These adjustments reduce NPC by \$0.9 million on a total Company
1995 basis.

1996 **Q. Has Mr. Falkenberg agreed with the Company's modeling of reserve**
1997 **shutdowns in another proceeding?**

1998 A. Yes. In Oregon Docket UM 1355, Mr. Falkenberg was a witness for ICNU, which
1999 was a party to a stipulation that adopted a calculation of the forced outage rate
2000 that incorporated reserve shutdowns in the same manner used by the Company in
2001 this proceeding.²³

2002 **Q. What are reserve shutdowns?**

2003 A. As defined by NERC, reserve shutdown hours are the hours in which a unit is
2004 available for service, but not electrically connected to the transmission system for
2005 economic reasons. The Company's calculation of forced outage rates is consistent
2006 with NERC's standardized industry formula.

2007 **Q. Does NERC include reserve shut down hours in its standard calculation of**
2008 **forced outage rates?**

2009 A. No. NERC, and standard industry practice, does not include reserve shutdown
2010 hours in the forced outage rate calculation. To do so would infer that in the time
2011 period in which a unit was disconnected from the system due to economic
2012 conditions, theoretically, it would have run the entire time it was off without
2013 incident. For example, if a unit runs 45 months out of a 48-month period and is in
2014 reserve shutdown for two months and planned outage for one month, the forced
2015 outage rate is calculated based on the 45 months of actual operations and the time

²³ *Re Pub. Util. Comm'n of Or. Investigation into Forecasting Forced Outage Rates for Electric Generating Units*, Docket UM 1355, Order No. 10-414, Appendix B at 10 (Oct. 22, 2010).

2016 periods in which the Company relied on the facility to run. To include the
2017 additional two months in the calculation simply lowers the forced outage rate
2018 because it mathematically makes the assumption that the unit operated perfectly
2019 for those two months. This is an unreasonable assumption and should not be
2020 adopted by the Commission.

2021 **Q. Do OCS and UIEC dispute the exclusion of planned outage hours in the**
2022 **calculation of forced outage rates?**

2023 A. No.

2024 **Q. Please explain the purpose and implication of excluding reserve shutdown**
2025 **hours in the calculation of outage rates.**

2026 A, Forced outage rates are used to project the percentage of time that units will not
2027 be able to generate during the test period. The purpose is not to duplicate the
2028 amount of generation lost in the historical period due to forced outages in the test
2029 period, which is dependent upon various factors in the test period, such as the
2030 length of time when the units are online and the market prices that determine
2031 whether it is economic to operate the units. The percentage of time that the unit is
2032 not available to generate during the entire test period due to forced outages is
2033 based on information available in a 48-month period when the unit actually
2034 operated. The information regarding whether the unit would be forced out if it
2035 were to be online during planned outage and reserve shutdown in the historical
2036 period can only be estimated with the information that is known to the Company.
2037 In the example above where the unit operated 45 months in the 48-month
2038 historical period, the outage rate for the forecast test period can only be

2039 determined based on the 45 months when the unit actually operated. Including
2040 reserve shutdown hours is as erroneous as including planned outage hours.

2041 **Q. Does the Company apply an outage rate of EFOR-d to reflect the reserve**
2042 **shutdowns of the peaking units?**

2043 A. Yes. This is also a modeling assumption that Mr. Falkenberg agreed to in Oregon
2044 Docket UM 1355 where he was a witness for ICNU.

2045 **Q. Is UIEC correct, that the calculation of forced outages is inconsistent with its**
2046 **application in the GRID model?**

2047 A. No. The use of forced outage rates in the GRID model is consistent with how they
2048 are calculated. Mr. Widmer's example, provided in MTW-2 is not illustrative of
2049 how GRID functions. For example, Mr. Widmer assumes that the GRID model
2050 will identically place the facility into reserve shutdown in the same manner in
2051 which it occurred in actual operations. This assumption does not take into
2052 consideration that reserve shutdowns are events that occur based on economic
2053 conditions; they are not preplanned or preprogrammed in GRID.

2054 **Miscellaneous Thermal Adjustments**

2055 **Chehalis Reserve Capability (DPU Adjustment 11 and OCS Adjustment 15)**

2056 **Q. Please explain DPU's and OCS's adjustments to the Chehalis reserve**
2057 **capability.**

2058 A. The Company has removed the reserve carrying capability of the Chehalis plant
2059 because Chehalis cannot currently provide operating reserves. DPU's and OCS's
2060 adjustments assume that Chehalis can provide operating reserves and decreases
2061 NPC by \$3.4 million and \$2.2 million on a total Company basis respectively.

2062 **Q. Why is Chehalis unable to provide operating reserves at this time?**

2063 A. Because the Chehalis plant is in BPA's balancing authority area, dynamic transfer
2064 capability is required in order for the Company to carry operating reserves at the
2065 Chehalis plant. On April 30, 2010, BPA rejected the Company's request for
2066 dynamic transfer capability. While the Company is actively working on this issue
2067 with BPA, the Company does not now have dynamic transfer capability.

2068 **Q. Are DPU and OCS correct that the Company previously stated that**
2069 **ownership of the plant would provide operating reserves, load following**
2070 **reserves and AGC?**

2071 A. Yes. Based on the Company's due diligence at the time, it reasonably believed
2072 this would be the case.

2073 **Q. What has changed since the Company performed its due diligence that**
2074 **makes these assumptions no longer true?**

2075 A. The Company has had discussions with BPA about either moving Chehalis
2076 electrically into the Company's balancing area or dynamically scheduling the
2077 plant over BPA transmission facilities. Either one of these outcomes would allow
2078 the Company to use the Chehalis plant to provide operating reserves. To date, the
2079 Company has not come to a satisfactory, final arrangement with BPA. The main
2080 concern is that BPA would require the Company to suspend all AGC in its west
2081 balancing authority area when BPA requested the Company to do so. This mode
2082 of operation to date has been unacceptable to the Company.

2083 **Q. Do you agree with OCS that the Company “should be held accountable for**
2084 **such promises”?**

2085 A. No. What OCS is actually proposing is a change to the concept of prudence.
2086 Currently, the Commission evaluates the assumptions made by the utility based
2087 on the best information known to the Company at the time the decision to acquire
2088 the resource was made. These assumptions will certainly change over time. In
2089 hindsight, some outcomes make the acquisition more attractive and others make it
2090 less attractive, but regardless, hindsight should not be used to determine prudence.
2091 Under OCS’s theory, regardless of the reasonableness of the Company’s decision
2092 at the time it was made, the Company should be held accountable for changes in
2093 circumstances or issues it could not have reasonably foreseen.

2094 **Q. OCS also claims that “[t]here is no reason why a modern combined cycle**
2095 **power plant should be incapable of providing operating reserves or that**
2096 **Chehalis could not have AGC installed” and DPU makes similar statements.**
2097 **How do you respond?**

2098 A. The issue is not one of physically being able to install AGC or provide reserves.
2099 As described above, the issue is operational and contractual. If the operational
2100 constraint can be removed and contracts agreed upon, then it would become a
2101 matter of the economics.

2102 **Q. OCS also claims that the Company should spend the estimated [REDACTED] to**
2103 **install the necessary infrastructure to reap the \$2 million benefit in reserve**
2104 **capability. Do you agree with this analysis?**

2105 A. No. If the operational and contractual constraints cannot be satisfactorily resolved,

2106 spending money on the installation of infrastructure would be pointless.

2107 **Q. Is the Company continuing to explore the possibilities for acquiring dynamic**
2108 **transfer capability for Chehalis?**

2109 A. Yes. The Company is continuing to discuss this issue with BPA and recently
2110 entered into an agreement with BPA that would allow dynamic transfer capability
2111 under certain conditions beginning in October 2011. The agreement with BPA has
2112 various off-ramps, however, and it is unclear whether the Company's efforts to
2113 achieve dynamic transfer capability for Chehalis will succeed in the rate effective
2114 period. Given the uncertainty, the Company does not believe it is appropriate to
2115 model operating reserve capability at Chehalis that does not currently exist. This
2116 is especially true given that the cost of achieving these operating reserves is not
2117 reflected in this case.

2118 **Q. Why is DPU's adjustment significantly higher than OCS's adjustment?**

2119 A. DPU applied a higher reserve capability for Chehalis. It is unclear what the source
2120 of the information is for DPU's adjustment. In any event, the overall economics
2121 associated with the Chehalis plant were significant, and overwhelm any reduction
2122 in benefits associated with the ability of the Chehalis plant to provide reserves to
2123 the system.

2124 **Station Service Corrections (OCS Adjustment 16)**

2125 **Q. What is OCS's adjustment to the modeling of station service in GRID?**

2126 A. OCS claims that the Company's modeling appears to contain three errors: one at
2127 Hunter, one at Currant Creek, and one at Chehalis. OCS's correction of these
2128 alleged errors decreases system NPC by \$0.3 million.

2129 **Q. What is station service?**

2130 A. Station service is the power consumption of a generation station. For most plants,
2131 the amount included in NPC is derived from the hourly generation logs, and only
2132 accounts for times when the generation logs show negative numbers. This is
2133 deemed to account for the station service used when the plant is off-line. Station
2134 service also occurs when a plant is on-line, but it is captured in the heat rate.

2135 **Q. How much station service has the Company included in NPC that relates to**
2136 **power consumption of the generation fleet for times units are off-line?**

2137 A. The Company included 85,368 MWh, or 9.7 average MW of station service in
2138 NPC of which 20,257 MWh are for Hunter, 3,121 MWh for Currant Creek and
2139 6,342 MWh for Chehalis.

2140 **Q. How much did Mr. Falkenberg reduce the station service requirements at**
2141 **each of these plants?**

2142 A. He reduced the station service requirement by 3,067 MWh at Hunter, 3,121 MWh
2143 at Currant Creek, and 3,123 MWh at Chehalis for a total adjustment of 9,311
2144 MWh or about one average MW.

2145 **Q. Are there reasons to believe that station service is understated?**

2146 A. Yes. The hourly generation logs, the data source for station service estimates for
2147 most plants, reflect net hourly generation. Hours in which a unit starts up or shuts
2148 down will reflect both positive and negative generation and will thus understate
2149 the total station service. In addition, the hourly generation logs are rounded to the
2150 nearest MW, and frequently include values of zero MW when units are offline. In

2151 reality, a unit will draw power in nearly all offline periods, so rounding also
2152 results in station service being understated.

2153 **Q. What does Mr. Falkenberg assume the station service requirements are for**
2154 **Currant Creek?**

2155 A. Zero.

2156 **Q. Is OCS's adjustment to Currant Creek's station service requirement**
2157 **reasonable?**

2158 A. No. The modeling of Currant Creek as a must run unit is designed to better reflect
2159 the Company's actual operational constraints within the GRID model. In reality,
2160 both of the Company's east side combined cycle facilities can provide operational
2161 flexibility, and the Company dispatches them based on availability and
2162 economics. In the 12 months ending June 2010, either Currant Creek or Lake Side
2163 was online in 94 percent of the hours. Any reduction in station service
2164 requirements at Currant Creek as a result of the must run operating constraint in
2165 GRID could result in an increase in Lake Side's station service requirements
2166 compared with historical operation. A modeling assumption does not make station
2167 service requirements disappear. All things considered, the historical data is the
2168 most reasonable basis for estimating the overall station service requirements
2169 included in the GRID model forecast.

2170 **Q. Under what conditions will Currant Creek be expected to require station**
2171 **service during the test period?**

2172 A. Whenever either combustion turbine at Currant Creek is offline, there will be a
2173 station service requirement that is only captured through the Company's station

2174 service estimate. The test period includes both forced and planned outages at
2175 Currant Creek, both of which would result in station service use, even when the
2176 unit is assumed to be operating in every hour of the test period. Mr. Falkenberg's
2177 assumption that there will be no station service at Currant Creek is unreasonable.

2178 **Q. How does the Company determine the station service requirements for the**
2179 **Chehalis plant?**

2180 A. Station service requirements for the Chehalis plant are based on bills from Lewis
2181 County Public Utility District who was the supplier of that service up until earlier
2182 this year.

2183 **Q. How did Mr. Falkenberg adjust the station service requirements for the**
2184 **Chehalis plant?**

2185 A. He took the information from the generation logs. Use of direct billings is
2186 straightforward and more accurate than estimating these values from the
2187 generation log.

2188 **Q. Is Mr. Falkenberg's adjustment for the Hunter plant reasonable?**

2189 A. Yes.

2190 **Cholla Reserve Capability (OCS Adjustment 17)**

2191 **Q. Please explain OCS's proposed adjustment to the capacity of Cholla Unit 4.**

2192 A. OCS claims that the Company's derate adjustment to Cholla Unit 4 should be
2193 changed based on the assumption that the 387 MW transmission limit functions to
2194 reduce the reserve capacity of the unit rather than the plant's output. OCS's
2195 adjustment would result in a \$0.9 million decrease to total Company NPC.

2196 **Q. Do you agree with OCS's application of the transmission limit by reducing**
2197 **the reserve capability?**

2198 A. No. OCS's adjustment artificially increases the generation from the plant, which
2199 is not possible to accomplish. In order for Cholla 4 to provide reserves, it is
2200 required to have transmission available when Cholla 4 is called upon to generate.
2201 Increasing Cholla 4's capacity for either generation or reserve leads to impossible
2202 operation of the plant.

2203 **Hydro Adjustments**

2204 **Q. Have OCS and UIEC proposed adjustments related to the Company's hydro**
2205 **forecast?**

2206 A. Yes. In addition to the Bear River hydro normalization and hydro outage
2207 normalization adjustments accepted by the Company, OCS proposes to adjust the
2208 modeling of Lewis River hydro and to remove hydro forced outage.

2209 **Q. Would these hydro adjustments result in a more accurate representation of**
2210 **hydro generation than the Company's modeling?**

2211 A. No. The Company's actual hydro generation has never exceeded what the
2212 Company has included in its base NPC, showing that the Company's hydro
2213 modeling consistently overstates hydro. The adjustments proposed by OCS would
2214 increase the inaccuracy of hydro generation.

2215 **Lewis River Hydro Modeling (OCS Adjustment 8)**

2216 **Q. Please explain the issue OCS raises with respect to the Lewis River Efficiency**
2217 **Loss and Motoring adjustments.**

2218 A. OCS has removed the effect of the Lewis River Efficiency Loss and Motoring

2219 adjustments because the Vista model does not optimize hydro reserve allocations.
2220 OCS does not challenge the legitimacy of these two adjustments, but argues that
2221 unless the Company implements all adjustments related to curing deficiencies in
2222 the Vista model, they should not include any. Conversely, if the Company
2223 includes the Lewis River Efficiency Loss and Motoring adjustment, it should also
2224 include OCS's screening adjustment to all hydro units with storage. The
2225 adjustment reduces system NPC by \$2.7 million.

2226 **Q. Please explain why you disagree with OCS's adjustment.**

2227 A. The Lewis River Motoring and Efficiency adjustments are not related to OCS's
2228 proposed adjustment. They are legitimate adjustments that have not been
2229 challenged on their merits. Motoring makes it possible for the units to handle
2230 reserves by drawing electricity as a load rather than using streamflow at a very
2231 inefficient level of generation. The efficiency adjustment is to reflect the fact that
2232 the hydro generating units are not able to run as efficiently as the Vista model
2233 optimizes. Neither is related to the amount of reserves that the Lewis River units
2234 may carry.

2235 **Remove Hydro Forced Outages (OCS Adjustment 9)**

2236 **Q. What is OCS's adjustment to hydro forced outages?**

2237 A. OCS objects to the Company's modeling of hydro forced outages and adjusts the
2238 modeling to reflect the 48 months ended June, 2010, assuming no energy lost and
2239 assumed that the value of rescheduled energy was the average market price during
2240 the year. This adjustment reduces system NPC by \$2.3 million.

2241 **Q. Is Mr. Falkenberg's adjustment to hydro forced outages reasonable?**

2242 A. No. Mr. Falkenberg's first assumption, that no energy is lost due to forced outages
2243 on hydro, is contradicted by his own testimony on page 26, where he cites data
2244 request OCS 20.9 showing an average energy loss of 10,299 MWh. Secondly, Mr.
2245 Falkenberg assumes that forced outages on hydro will occur such that over the
2246 year they will result in a value that is equivalent to the average market price. This
2247 assumption does not take into consideration that hydro units do not operate
2248 throughout the year; they operate predominantly in on-peak periods. Therefore, a
2249 reflection of the average market price, taking into consideration off-peak hour
2250 prices, is not a reasonable assumption or calculation.

2251 **Start Up Adjustments (OCS Adjustment 3)**

2252 **Start-up Fuel Costs – Outage Adjustment**

2253 **Q. What is OCS's adjustment related to start-up fuel costs?**

2254 A. OCS argues that start-up fuel costs should be adjusted to account for days lost to
2255 forced outages, reducing total Company NPC by \$0.3 million.

2256 **Q. How do you respond to OCS's proposal that start-up fuel costs be lowered to
2257 account for forced outages?**

2258 A. The adjustment is illogical. Start-up fuel costs are related to plant start ups and
2259 have nothing to do with forced outages.

2260 **Q. Is OCS's adjustment one-sided?**

2261 A. Yes. A portion of the forced outages that the Company uses to determine the level
2262 of normalized outages in the current proceeding were full outages. That is, the
2263 units were forced to be offline completely, and would require startup when

2264 coming back online. OCS has not proposed additional startup fuel costs of such
2265 outages, either in relation to this adjustment or to its adjustment for heat rate and
2266 minimum generation duration.

2267 **Start-up Energy Value**

2268 **Q. What is OCS's proposal related to start-up energy?**

2269 A. OCS argues that the Company should reflect energy produced during start up in
2270 NPC. OCS's adjustment would reduce system NPC by \$0.8 million.

2271 **Q. In your direct testimony, you explained that accounting for start-up energy**
2272 **using the methodology proposed by DPU would increase NPC by \$0.6 million**
2273 **on a total Company basis. Mr. Falkenberg questions the accuracy of your**
2274 **calculation. Please respond.**

2275 A. First, since the Company had to address this issue before it had prepared its 2010
2276 NPC study, it had to be based on the 2009 NPC study since that was the most
2277 recent information the Company had to work with at the time. Second, the
2278 Company applied the methodology used by DPU in the 2009 case because it was
2279 clearly defined, and also approximated the value of start-up energy more closely
2280 than other proposals.

2281 **Q. Do you agree with Mr. Falkenberg that the value of the start-up energy**
2282 **should be evaluated in GRID?**

2283 A. No. In addition to what I have discussed in my direct testimony that the start-up of
2284 the gas-fired units causes redispatch of other resources to operate at less-than-
2285 optimal level, such impact is within an hour. GRID dispatches all resources on an
2286 hourly basis, so is the Vista model that optimizes hydro generation. Furthermore,

2287 there is currently no intra-hour market for energy transactions, modeling the start-
2288 up energy in GRID implies that the Company may be able to sell energy or avoid
2289 buying energy on an intra-hour basis, which is contrary to reality.

2290 **Q. Is Mr. Falkenberg's calculation that uses the value of coal energy to**
2291 **approximate a more detailed modeling approach reasonable?**

2292 A. No. Instead of avoiding his own criticism of Company's methodology for not
2293 modeling start-up energy in GRID, Mr. Falkenberg made a financial adjustment
2294 based on the Company's study in the direct case and applied the same
2295 methodology used by DPU that the Company applied in its analysis. For reasons
2296 discussed in my direct testimony, the Company did not model the extended
2297 minimum downtime for the start-up energy because the Company does not
2298 believe the value of start-up energy. If Mr. Falkenberg were to extend the
2299 minimum downtime, the number of start-ups of the units will reduce, so will the
2300 amount of start-up energy. In addition, it is unclear what the source information is
2301 for OCS's amount of energy per start-up. I recommend the Commission adhere to
2302 its decision in the 2009 GRC rejecting the start-up energy adjustments.

2303 **NPC Conclusion**

2304 **Q. Please summarize your recommendations on NPC.**

2305 A. I recommend the Commission adopt the Company's rebuttal NPC of \$1.508
2306 billion. Based on its filing in Oregon, the Company expects its actual NPC will be
2307 even higher in the rate effective period.

2308 I also recommend that the Commission acknowledge that updates at the
2309 time of the Company's rebuttal filing are appropriate and necessary to achieve the

2310 most accurate NPC forecast, regardless of whether NPC increase or decrease. In
2311 this case, the Company's updates reduce NPC from its original filing by
2312 approximately \$12.9 million.

2313 **Q. How do you plan to make your NPC forecast more accurate in subsequent**
2314 **GRC filings?**

2315 A. The Company will continue to investigate methods to improve GRID's systematic
2316 understatement of NPC that result from GRID's use of static assumptions to
2317 forecast an environment characterized by volatility in loads, resources and
2318 markets.

2319 **Section II - Apex**

2320 **Q. What is the purpose of your testimony on Apex in this Docket?**

2321 A. Regarding the Apex facility, I will respond to the testimony and proposed
2322 adjustments sponsored by Messrs. Richard S. Hahn and Charles E. Peterson on
2323 behalf of the DPU.

2324 **Q. Please explain how this section of your testimony is organized.**

2325 A. I will demonstrate that the Company's decision to terminate Apex was prudent
2326 and in customers' best interest.

2327 First, I will show that consistent with the Commission's Approved
2328 Evaluation Methodology for this RFP, which was approved by the Commission in
2329 Docket No. 10-035-126, the economic evaluation of Apex results in a \$12 million
2330 present value revenue requirement (PVRR) customer *harm* on a Utah basis²⁴, and
2331 explain why the DPU's assertion that the economic evaluation of Apex results in

²⁴ The study requested by the Independent Evaluator in data request DPU 2.7 in Docket No. 10-035-126, which is most closely aligned with the Approved Evaluation Methodology was \$28m unfavorable to Apex, which is \$12m unfavorable on a Utah allocated basis.

2332 a \$57.6 million PVRR customer benefit on a Utah basis is invalid. I demonstrate
2333 that the studies relied on by the DPU to estimate potential damages to customers
2334 based upon the Company's decision to not acquire Apex are inherently flawed
2335 because they unreasonably force the Company to substitute high-cost unmet
2336 energy demand for Apex, without any ability to satisfy that energy demand with
2337 any other resource and are inconsistent with the Approved Evaluation
2338 Methodology and the Commission's Order.

2339 Second, I will show that the DPU's studies supporting their proposed
2340 \$57.6 million lump sum adjustment ignores material risks associated with the
2341 acquisition of Apex, in particular the timing and cost risks that are associated with
2342 the transmission infrastructure needed to deliver the Apex plant's output to serve
2343 RMP's customer load. In addition to excluding these significant and material risks
2344 in their assessment, DPU's analysis assumes that customers would immediately
2345 receive a benefit from Apex, which even in the flawed studies they rely upon,
2346 wouldn't be realized until at least year 2024, if ever.

2347 Third, I will rebut the policy behind DPU's attempted use of
2348 unprecedented ratemaking to penalize the Company solely because DPU
2349 disapproves of the "process" by which the Company terminated its negotiations
2350 for the Apex facility. As described in the rebuttal testimony of Mr. Stefan Bird, in
2351 Docket No. 10-035-126, which has been adopted as an exhibit to Mr. Peterson's
2352 testimony, the Company completed a thorough and intensive due diligence
2353 process that supported the analysis demonstrating the Apex plant was not the least
2354 cost, on a risk adjusted basis, resource for customers. DPU is simply attempting to

2355 penalize the Company (it admits as much—Peterson transcript of hearing, page
2356 76, line 21-23) because it did not approve of the process the Company took in
2357 making that decision, as it has no evidence that it was ultimately the wrong or an
2358 imprudent decision.

2359 Lastly, I point out the irrelevance of the cases from Maine and
2360 Massachusetts described by Mr. Hahn, noting how they differ from settled policy
2361 law in Utah.

2362 In conclusion, although the Company is confident that the evidence
2363 supports the Company's decision to terminate negotiations to acquire Apex was in
2364 the best interest of customers, the Company recognizes lessons learned from the
2365 RFP and proposes to hold a stakeholder workshop in advance of the issuance of
2366 the next RFP to consider process improvements and revisit the Approved
2367 Evaluation Methodology to assess and implement improvements to address more
2368 unique opportunities like Apex.

2369 **Apex Termination**

2370 **Q. Please briefly explain why the Company's decision to terminate negotiations**
2371 **for the Apex facility was in the best interest of customers.**

2372 A. As explained more fully in my rebuttal testimony in Docket No. 10-035-126, also
2373 incorporated herein, the decision to terminate negotiations for the Apex facility
2374 was made after a comprehensive and thorough economic evaluation and due
2375 diligence process. The Company has demonstrated that the termination of
2376 negotiations with LS Power was a prudent decision that was in customers' best
2377 interest and was not terminated prematurely as argued by Mr. Peterson. The

2378 evaluation requested by the IE, which incorporates the updated assumptions
2379 resulting from extensive due diligence (DPU 2.7) demonstrated that Apex was not
2380 an economic opportunity at the time the decision was made, and showed that
2381 acquisition of Apex would have caused highly certain and significant near-term
2382 rate increases on the gamble that long-term net variable cost savings would be
2383 realized. Before even considering material acquisition risks, such as those related
2384 to the timing and cost of transmission upgrades on both NV Energy's and
2385 PacifiCorp's transmission systems, this study shows that Apex plant is
2386 approximately \$12 million unfavorable to Utah customers. Due diligence had
2387 been completed at the time the decision to terminate negotiations with LS Power
2388 was made and there was no further evidence to be gathered. Indeed, the Utah
2389 Independent Evaluator (I.E.) praised the Company for the thoroughness of its due
2390 diligence and information gathering process. Accordingly, there was no need to
2391 prolong the process by which the Company informed LS Power, DPU, or the IE
2392 of the Company's decision.

2393 **Q. What risks did the Company consider when it determined that Apex was not**
2394 **an prudent option to pursue at this time?**

2395 A. Most importantly, the Company's due diligence and risk assessment revealed
2396 significant transmission constraints preventing Apex from timely delivering its
2397 output to the Company's retail customers. If acquired, the Apex project would
2398 have carried significant regulatory risk of not being deemed used and useful in
2399 providing service to retail customers until such future time as it becomes able to
2400 fully deliver its power load to our customers. This risk is exacerbated by reliance

2401 on not just one, but two different transmission providers, PacifiCorp Transmission
2402 and NV Energy, to complete necessary upgrades within the timeframe and cost
2403 assumed. The PacifiCorp Transmission due diligence report highlighted that there
2404 are significant upgrades required to transfer Apex's generation output to Utah
2405 customers with costs ranging between \$70 million to \$300 million, depending on
2406 the results of a sub-synchronous resonance study to determine if the proposed
2407 Sigurd-Mona 345kV series compensation is even feasible. The Company's
2408 analysis which show Apex to be uneconomic, as well as the flawed DPU studies,
2409 were conducted using the \$70 million transmission upgrade assumption, i.e., the
2410 best-case scenario for Apex. Thus the economics for Apex could only get worse if
2411 the transmission costs turned out higher than the best case scenario and/or were
2412 not timely completed as assumed in the studies.

2413 Moreover, even if the required PacifiCorp Transmission and NV Energy
2414 transmission upgrades were made, there is no guarantee that any such upgrade
2415 would be made in a timely fashion and ensure the Apex resource would be able to
2416 meet the Company's load obligations.

2417 **Q. Please explain the impact these risks had on the Company's decision to**
2418 **terminate its negotiations for the Apex facility.**

2419 **A.** When one examines the analysis results even more closely, it is evident that near-
2420 term fixed costs, which are known with relatively high confidence, outweigh the
2421 net variable cost benefits, which are much more uncertain, and do not materialize
2422 until after 2023, if at all. Consequently, acquisition of Apex would have caused
2423 highly certain and significant near-term rate increases on the gamble that long-

2424 term, uncertain, net variable cost savings would be realized. Such a gamble is not
2425 prudent. Thus, Apex was not and is not in the interest of customers. It was
2426 uneconomic, even giving it the benefit of numerous best case scenario
2427 transmission cost and schedule assumptions, and was fraught with risks beyond its
2428 lack of economic contribution.

2429 **Q. Why did the Company have a concern that in a future proceeding the**
2430 **Commission might determine that the Apex facility was not used and useful?**

2431 A. Apex is dependent on transmission, yet to be built by two different entities, in
2432 order to deliver its output to meet the Company's retail load. This transmission
2433 has a risk of never being built, thereby leaving the Apex plant stranded from retail
2434 loads.

2435 **Q. Were there any additional physical attributes of the Apex facility that caused**
2436 **the Company to be concerned about its ability to produce a favorable benefit**
2437 **to customers?**

2438 A. Yes. Because Apex lacks backup from the Company's system as a result of
2439 transmission limitations even if all the assumed upgrades were completed, any
2440 sale of power from Apex to the wholesale market will be for non-firm power,
2441 known as "shaft contingent." This means there is significant risk that the
2442 Company may not be able to realize the wholesale benefits for Apex that the
2443 DPU's models rely on to demonstrate economic value to the plant.

2444 **Q. What does the term "shaft contingent" mean?**

2445 A. Essentially, shaft contingent simply means that the facility could not provide firm
2446 power and would be considered "non-firm" unit-contingent power in the

2447 wholesale market. In other words, if the Apex plant or the transmission in or out
2448 of the plant experienced an outage, any sale of power from the plant would have
2449 to be cut. Because it is not backed by reserves that would ensure potential
2450 wholesale transactions would occur even upon loss of the unit, this “non-firm”
2451 power is considered to be less valuable, and less marketable than “firm power”.
2452 The Company has minimal history of success selling non-firm power. For those
2453 reasons, this type of power presented considerable risk that the potential modeled
2454 wholesale sales revenue attributable to Apex would not actually materialize.

2455 **Q. Mr. Hahn states that the Company is in a position in which it will require**
2456 **additional capacity that could have been met with the Apex resource. Does**
2457 **Apex represent the least cost resource for this identified need in 2011 and**
2458 **beyond?**

2459 A. No. The Company will supply any required energy identified in the 2011
2460 Integrated Resource Plan (IRP) from either market purchases or purchases from
2461 merchant resources on the east side of the system at a cost to ratepayers that is
2462 substantially *lower* than the Apex project. These resources will be procured
2463 through market purchases at Mona and the Nevada/Utah border as well as from
2464 existing generation inside of Utah at a lower cost and lower risk to customers than
2465 Apex. Simply stated, Apex is not the Company’s only alternative to providing
2466 power, but the DPU continues to base its position on modeling that assumes that it
2467 is.

2468 **DPU’s flawed analysis**

2469 **Q. Is the analysis used by Mr. Peterson and Mr. Hahn to calculate their estimate**
2470 **of “harm” associated with the Company’s decision to not acquire Apex at**
2471 **this time consistent with the Commission’s own Approved Evaluation**
2472 **Methodology?**

2473 A. No. The analysis referenced by Mr. Peterson and Mr. Hahn to calculate their best
2474 estimate of economic loss was based on discovery requests DPU 4.23 and DPU
2475 9.1 which were deferral analyses requested by the DPU using resources in
2476 Portfolio 2 (Apex + Lake Side 2) and allowing Currant Creek II and other
2477 resources to “float” beyond 2016, and then further, *not* allowing Currant Creek II
2478 to be selected until after 2016. This study was requested by the DPU and provided
2479 by the Company in Docket No. 10-035-126. Again, their study was designed to
2480 not let Apex be “outdone” by another plant, and to compete only against
2481 intentionally high priced alternatives for energy not served.

2482 **Q. Did this study comply with this Commission’s Approved Evaluation**
2483 **Methodology?**

2484 A. No, because the Commission Approved Evaluation Methodology did not allow
2485 deferral analyses where resources were allowed to “float” in the model runs.

2486 **Q. Please describe what is meant by the term “float” in that context.**

2487 A. Allowing potential power sources to “float” means that the types, quantities, and
2488 timing of future resources are allowed to change.

2489 **Q. Would such a study comply with this Commission’s Order?**

2490 A. No. The Order states the following:

- 2491 1) The Company [is] to use its proposed methods for comparing portfolios
2492 and identifying final shortlist resources, with the exception noted herein;
2493 2) The Company shall include a zero cost per ton of carbon tax in its
2494 deterministic and stochastic analysis and portfolio ranking metric;
2495 3) The Company shall establish the initial shortlist by September 1, by each
2496 fuel type, in each eligible category; and
2497 4) The Company shall use the Step 3b results in its determination or ranking
2498 of final shortlist and explain how it does so.

2499 **Q. Please explain the Approved Evaluation Methodology for comparing**
2500 **portfolios and identifying shortlist resources.**

2501 A. The white paper titled the Final Short List Development for the All Source
2502 Request for Proposals dated November 16, 2009 was filed with the Utah
2503 Commission on November 16, 2009 under Docket No. 07-035-94. “The proposed
2504 methods for comparing portfolios and identify final shortlist resources were as
2505 follows. The starting point for System Optimizer portfolio development is the set
2506 of preferred resources and input assumptions from PacifiCorp’s 2009 business
2507 plan and the 2008 IRP. The preferred portfolio resources, developed assuming a
2508 12 percent capacity planning reserve margin, will be removed as resource options
2509 in order to create a capacity deficit that the model must fill with combinations of
2510 bid and benchmark resources. (The model is also allowed to select a variable
2511 quantity of firm market purchases, or “front office transactions” to ensure that a
2512 specified annual planning reserve margin is maintained.) Resource additions past

2513 2020 will be fixed for all portfolios to remove the impact of out-year resource
2514 optimization on bid/benchmark resource selection.”

2515 **Q. Did the Approved Evaluation Methodology contemplate allowing resources**
2516 **to “float” as the DPU’s studies have done?**

2517 A. No, it specifically prohibits allowing resources to float.

2518 **Q. Was the Approved Evaluation Methodology reviewed by the IE and the DPU**
2519 **and adopted by the Commission?**

2520 A. Yes. It is what is referred to throughout this testimony as the Commission
2521 Approved Evaluation Methodology, which is the same description used in the
2522 Commission’s order in Docket No. 10-035-126.

2523 **Q. Is it reasonable for Mr. Peterson or Mr. Hahn to claim that Utah customers**
2524 **have been damaged by approximately \$56.6 million?**

2525 A. Absolutely not. First, the analysis is flawed. A reasonable interpretation of the
2526 appropriate study would be that requested by the IE which shows that a decision
2527 to acquire Apex would result in at least a \$12 million PVRR customer increased
2528 cost. Moreover, there is a significant amount of transmission and other risks that
2529 would need to be overcome for Apex to provide *any* benefit. The Company has
2530 not completed the sub-synchronous transmission study and therefore none of the
2531 parties know if the Apex costs will increase as much as an additional \$300 million
2532 over the costs already included in the Company’s studies. In its evaluation, the
2533 Company determined that, due to the fact that the transmission study would
2534 demonstrate only an *increase* in costs for Apex, the study did not need to be
2535 completed to determine whether the Company should acquire Apex at this time.

2536 That is, the study would only have further demonstrated how *much more*
2537 *uneconomic* Apex would have been. There is no scenario in which that study
2538 would have produced a positive number, bolstering Apex's economics. Mr. Hahn
2539 and Mr. Peterson simply ignore the transmission challenges of Apex in their
2540 analysis.

2541 Therefore, there is no certainty of any benefits from Apex. The only
2542 certainty is that customer costs would be significantly greater than without Apex
2543 for several years. The \$56.6 million figure proposed by the DPU is a speculative
2544 and contrived scenario that the DPU claims could unfold in the future. There is
2545 absolutely no actual evidence on which this Commission could base a rate
2546 decision using that number. It is pure conjecture.

2547 **Q. The DPU has also proposed an alternative yearly penalty to the Company in**
2548 **lieu of a lump sum adjustment. Is the Company willing to accept this**
2549 **proposal?**

2550 A. No. Again, the DPU is simply attempting to extract a penalty in the guise of rates
2551 because it did not like the Company's process. It has put forward no evidence that
2552 customers in Utah were actually harmed by this decision. Instead it presents
2553 hypotheticals, based on flawed studies, of possible future damages, all of which
2554 assume such things as certain abilities to acquire transmission, at set best case
2555 scenario costs and schedule, at set natural gas prices (notably higher than those
2556 known at the time the decision was made to terminate negotiations), at set CO₂
2557 tax levels (where there is considerable uncertainty), at set natural gas
2558 transportation costs, to claim the acquisition of Apex was favorable. The DPU's

2559 yearly adjustment proposal blatantly admits that the DPU is seeking a penalty, not
2560 seeking a fair rate for customers based on actual costs, as it concedes that
2561 information gathered by the DPU in the future may well prove to its satisfaction
2562 that the Company was right all along, meaning the “penalty” should stop at that
2563 time. The DPU provides no support for its novel proposition, however, that a
2564 utility should pay a penalty in the form of an artificial rate level until such time as
2565 the DPU becomes convinced that Company management made a good decision.

2566 **Q. Has the DPU requested additional studies that they believe will support their**
2567 **proposed penalty disallowance?**

2568 A. Yes. In their testimony, Mr. Peterson and Mr. Hahn reference additional studies
2569 the DPU requested the Company provide.

2570 **Q. Has the Company responded to these requests?**

2571 A. Yes. The Company responded that it does not have the requested analysis and
2572 furthermore, the results of that analysis would not be meaningful even if the
2573 Company did have it

2574 **Q. If the Company had performed the requested studies why would the results**
2575 **not be meaningful?**

2576 A. The DPU requested that the Company provide a study in which Apex was
2577 excluded from the resource portfolio, that also excluded the Currant Creek 2
2578 resource until *after* 2016, and that further would allow the System Optimizer
2579 model to select the amount and timing of resources to be procured *beyond* 2016.
2580 These study parameters would necessarily create a capacity shortfall in 2016 and
2581 would result in unserved load. That is, the study was set up to compare one

2582 scenario with Apex to another scenario that not only excluded Apex, but also
2583 excluded any replacement resource to Apex, and instead assumes all of that future
2584 energy will be filled by spot-market purchases, or front office transactions
2585 (“FOTs”).

2586 DPU requested the Company provide stochastic and deterministic results
2587 using these flawed study designs.

2588 **Q. Please further describe why these studies are unreasonable?**

2589 A. It is unreasonable to design a study that artificially adds resources or market
2590 access that do not exist (such as Apex’s non-existent transmission) or knowingly
2591 fails to meet load (that is, does not allow Current Creek II or other resources to
2592 meet the resource need). Recognizing that there would be a capacity shortfall in
2593 2016, the DPU requested that the study be completed by artificially relaxing FOT
2594 limits in 2016, and in the alternative, by allowing capacity shortfalls to be met
2595 with high cost unmet energy and unmet capacity.

2596 The first alternative is not reasonable because it increases FOT limits
2597 beyond what is possible, given the Company’s firm transmission rights to trading
2598 hubs, and requires the model to assume market purchases at volumes in excess of
2599 the market depth at a given trading hub. As such, the relaxed FOT assumption
2600 does not reflect what the Company could or would reasonably do to meet its load
2601 obligations in 2016.

2602 The second alternative that would allow capacity shortfalls to be met with
2603 unmet energy and unmet capacity is equally non-representative of what would
2604 actually occur in absence of Apex. When the Company anticipates a capacity

2605 shortfall, the Company issues an RFP to fill that shortfall with the most cost
2606 effective resource, adjusted for risk, that is in the public interest. The Company
2607 cannot plan to have unmet energy and unmet capacity as a cost effective
2608 alternative that is in the public interest due, in part, to its obligation to serve.
2609 Consequently, the unmet energy and unmet capacity assumption in the DPU study
2610 does not reflect reasonable resource alternatives and inappropriately assumes that
2611 Apex, and Apex alone, would offset unmet energy and unmet capacity costs in
2612 2016. That is, the DPU assumes Apex is the Company's only alternative to
2613 meeting future energy demand. That assumption is unreasonable and far from the
2614 truth.

2615 **Q. Were the requested analyses consistent with the Commission Approved**
2616 **Evaluation Methodology?**

2617 A. No.

2618 **Unprecedented Ratemaking Policy and Penalties**

2619 **Q. Is the economic loss calculation proposed by Mr. Peterson consistent with**
2620 **rate making practices?**

2621 A. No. I believe Mr. Peterson's recommendation raises significant new policy and
2622 implementation issues that are not appropriate. The proposal to penalize the
2623 Company for not taking certain action is unprecedented, unfair and unbalanced as
2624 it does not give the Company any opportunity to offset penalties with premiums.

2625 **Q. Does Mr. Peterson’s recommendation represent a change in policy that may**
2626 **have long term implications on future Company decisions?**

2627 A. Yes. Mr. Peterson’s recommendation introduces a slippery slope, setting a
2628 precedent in which any decision to not acquire a resource or to not enter into a
2629 contract would need to be litigated to determine the penalty or premium for the
2630 Company taking such action. Mr. Peterson’s recommendation further appears to
2631 violate cost of service ratemaking since it relies on hypothetical unrealized
2632 benefits, as opposed to actual costs of service, to get rates. It requires the
2633 Commission to adopt performance-based ratemaking, not cost-based ratemaking.

2634 **Q. But isn’t DPU’s proposed adjustment of \$56.7 million cost-based?**

2635 A. No. It is only a hypothetical projection of possible lesser-costs that theoretically
2636 could be achieved over the next 20 years if *Apex and no alternative to Apex*, is
2637 added to the system over that same period of time. The \$56.7 million is made up
2638 of three parts: 1) net costs, 2) unmet energy, and 3) a risk premium. The stochastic
2639 analysis relied on by DPU is reasonable for planning and resource procurement
2640 decisions, but not for ratemaking. Unmet energy and a risk premium have no
2641 place in cost of service ratemaking. Therefore, even if one were to adopt the use
2642 of unrealized benefits for ratemaking, the only aspect of that case that would be
2643 valid would be the net costs, which show Apex would result in a net \$12 million
2644 cost, rather than any benefit.

2645 **Q. Have you previously identified this issue, that Mr. Peterson’s proposed**
2646 **adjustment is a departure from the cost of service rate making, used in**
2647 **general rate case and net power cost proceedings?**

2648 A. Yes. In my rebuttal and surrebuttal testimony, in Docket No. 10-035-126, I
2649 discussed this point at length.

2650 **Q. Did Mr. Peterson provide a response to the Company’s point that his**
2651 **adjustment is a significant departure from cost of service ratemaking**
2652 **principles?**

2653 A. No. Mr. Peterson has continued to support his proposed adjustment without ever
2654 addressing why such a significant departure from the Utah Commission’s rate
2655 making policy is appropriate.

2656 **Q. Has Mr. Peterson made statements that undermine his testimony that this**
2657 **resource would have provided an economic benefit to customers?**

2658 A. Yes. The Company cites the following excerpt from the transcript of hearing
2659 proceedings on the approval of Lake Side II in Docket No. 10-035-126, wherein
2660 Mr. Peterson made the following statement in answer to questions from Mr.
2661 Moscon:

2662 Mr. Moscon: “And so if the Commission were to undertake a
2663 proceeding now asking it to value out, for the next 20 years, the impact
2664 to ratepayers for not having that resource, a subsequent acquisition of
2665 that resource or a different resource is going to mean all that analysis
2666 that just took place is really one-sided, or unfair, isn’t that correct?”

2667 Mr. Peterson: “I don’t understand how it could be one-sided and
2668 unfair. If the Commission determines that the Company did not behave
2669 in the public interest when it terminated—determined to terminate
2670 Apex over a weekend, then that is the issue and it’s a singular issue,
2671 and you don’t—and once that’s determined, then some sort of
2672 consequence, I suppose, would need to be applied for the Company
2673 not behaving—or behaving poorly or badly.

2674 If, subsequently, you [RMP] didn't purchase Apex, that would just be
2675 wonderful, but we're focusing on the failure of the Company to follow
2676 process.” (Emphasis added.)

2677 Mr. Moscon: “I understand that. I'm just trying to make sure I'm clear
2678 as to what your recommendation is when you say they ought to open
2679 another docket, and I'm trying to explore how that would come to any
2680 real understanding of value to the ratepayers. Let me just kind of focus
2681 it this way: you indicated in your summary that you agree with Mr.
2682 Oliver as to his conclusions. When Mr. Oliver was on the stand, I
2683 heard him indicate that, as he sits here, he doesn't know whether the
2684 Company should have or should not have acquired Apex. He believes
2685 there's just not enough analysis. Do you agree with that point?

2686 Mr. Peterson: “I agree that, upon further analysis, that may be the
2687 conclusion.”

2688 This transcript shows that Mr. Peterson does not have any actual evidence that
2689 the Apex facility was in the best interest of customers, and further, he is

2690 simply attempting to penalize the Company for “process”, based on an
2691 erroneous belief that the Company acted too hastily in terminating
2692 negotiations for the Apex facility.

2693 **Q. Is it reasonable for DPU to recommend an adjustment to rates, based on**
2694 **results that did not allow the Utah Independent Evaluator (“IE”) to find that**
2695 **the plant should be acquired, and are intended simply as a penalty for what**
2696 **it perceives as a lack of process?**

2697 A. No. Mr. Peterson remarks several times on the Company’s “weekend evaluation”
2698 but he does not cite a failure with the Company’s due diligence conclusion, which
2699 was that the lack of an economic benefit, transmission issues, and subsequent
2700 used and useful issues that caused the Company to terminate its negotiations with
2701 Apex were incorrect. To the contrary, Mr. Peterson and Mr. Hahn have simply
2702 ignored that they exist.

2703 **Incomparable Utility Examples**

2704 **Q. Do you agree with Mr. Hahn’s testimony that the rejection of Apex is**
2705 **comparable with two cases where a utility was found to be imprudent for**
2706 **specific acts of omission.**

2707 A. No. Both cases are distinguishable from this situation.

2708 The case from Massachusetts deals with a settlement between a utility and
2709 the state’s attorney general’s office where the utility allowed a fuel supplier to
2710 breach a fuel supply contract, and instead of suing the fuel supplier, merely
2711 entered into other higher-cost contracts. Those facts have no bearing to this
2712 situation. Moreover, the amount of fuel cost in the original, breached contract

2713 compared to the replacement contracts was an actual cost, indisputable by either
2714 party.

2715 The second case, from Maine, involved an undisputed series of decisions
2716 by a utility that also allowed QF Contracts to be breached, with no steps being
2717 taken to put customers in as good of a position as if the Company had enforced its
2718 contractual rights. This occurred over multiple “years”. Again, unlike our scenario
2719 with Apex, there was no disputing the fact that breaches of contracts had
2720 occurred, and that the utility failed to take any steps to protect customers. That is
2721 not the Apex scenario. Here, the Company believes that it has taken the very step
2722 it should have taken to protect customers: not acquire Apex at this time.

2723 **Q. Have you been advised of any Dockets in which the propriety of second**
2724 **guessing such a management decision was an issue?**

2725 A. Yes, I was advised of, for instance, Logan City v. Public Utilities Commission,
2726 296 P. 106 (Utah 1931). There, the Utah Supreme Court addressed this very type
2727 of dispute: what to do when a third-party challenges whether a utility’s
2728 management had made the most economic decision for its customers about how to
2729 better a utility’s system. That Court stated, “Whether this method of bettering its
2730 system was most economic or efficient was a matter within the sound discretion
2731 of management. It is well settled that Public Commissions cannot, under guise of
2732 rate regulation, take into their hands the management of utility properties or
2733 unreasonably interfere with the rights of management.” Id. at 446.

2734 So while Mr. Hahn’s cases involve undisputed issues of a utility failing to
2735 act to protect customers, previous decisions from this state seem to counter the

2736 policy behind Messrs. Peterson and Hahn's position, which is to penalize
2737 management for its business process without respect to whether it was the right
2738 decision.

2739 **Q. Does the Company recognize any lessons learned that would address the**
2740 **issues highlighted by the DPU?**

2741 A. Yes. Although the Company is confident that it made the appropriate decision
2742 regarding Apex, in light of the reaction of the DPU and the IE to the process
2743 followed by the Company, the Company is willing to conduct a workshop prior to
2744 the issuance of the 2011 request for proposals in December 2011 to seek input
2745 from stakeholders, the DPU and the IE on how the Company can improve the
2746 overall process associated with the selection or rejection of specific proposals and
2747 revisit the Approved Evaluation Methodology to assess and implement
2748 improvements.

2749 **Apex Summary**

2750 **Q. Please summarize your recommendations on Apex.**

2751 A. I recommend the Commission reject the DPU's adjustment to penalize the
2752 Company for a process issue when the Company made a prudent decision that is
2753 in the interest of customers. Further, I recommend that the Commission address
2754 the process issues by establishing a workshop prior to the issuance of the 2011
2755 request for proposals to improve and address the process issues raised by the
2756 DPU.

2757 **Section III – Hedging**

2758 **Q. What is the purpose of Section III of your rebuttal testimony?**

2759 A. My rebuttal testimony addresses the Company's hedging strategy and practices
2760 and demonstrates why the associated costs are prudent and reasonable.
2761 Specifically, I respond to the adjustments for hedging costs proposed by Messrs.
2762 Wheelwright and Crisp on behalf of the DPU; Ms. Beck, Dr. Schell and Mr.
2763 Wielgus on behalf of the OCS; Messrs. Higgins and Fishman on behalf of UAE;
2764 and Messrs. Malko and Widmer on behalf of UIEC. Company witnesses Messrs.
2765 Bird and Apperson and Mr. Graves from The Brattle Group also respond to
2766 particular aspects of the hedging adjustments proposed by intervenors.

2767 **Q. Please summarize your testimony.**

2768 A. I demonstrate that the Company's hedging program has reduced the volatility of
2769 NPC. I also sponsor quantitative analysis showing the benefits customers have
2770 received in NPC as a result of the Company's hedging program.

2771 **The Company's Hedging Program Reduces Volatility**

2772 **Q. Parties to this case have questioned whether the Company's hedging**
2773 **program benefits customers by reducing volatility in the Company's NPC.**

2774 **Please respond.**

2775 A. I recently addressed this issue in my testimony in the ECAM docket.²⁵ I
2776 demonstrated that the Company's hedging program reduces NPC volatility caused
2777 by changes in market prices and protects against high NPC outcomes.

²⁵ *Re Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism*, Docket 09-035-15, Phase 2 Rebuttal Testimony of Greg Duvall at 14 (September 10, 2010).

2778 **Q. Does this testimony remain valid?**

2779 A. Yes.

2780 **Q. Please specifically respond to the OCS's claim that the Company's hedging**
2781 **program does not reduce the volatility of NPC.**

2782 A. OCS makes this claim based upon Exhibit OCS 6.1. This analysis does not
2783 demonstrate the volatility of net power costs. This analysis demonstrates only
2784 changes in the test year NPCs with and without natural gas and power swaps,
2785 which are only a subset of the Company's total hedges.

2786 **Q. Is OCS's current position that the Company's hedging program does not**
2787 **reduce volatility contrary to the position OCS took in the ECAM docket?**

2788 A. Yes. Dr. Schell testified in that docket that the Company had well-defined
2789 hedging targets, that its hedging program complied with these targets, and the
2790 combined impact of the 48 month hedging horizon and the hedging volume
2791 targets was to help the Company meet its goal of reducing NPC volatility.²⁶ When
2792 Dr. Schell proposed to reduce the Company's hedging targets in that docket, she
2793 acknowledged that this would increase rate volatility experienced by customers.²⁷

2794 **Q. Has the Company developed additional analysis since the time of your**
2795 **ECAM testimony on the issue of NPC volatility and hedging?**

2796 A. Yes. The Company's 2011 IRP addresses this issue and demonstrates that the
2797 Company's approach to hedging, which is both comprehensive and integrated
2798 from a power/natural gas standpoint, reduces the volatility of NPC. First, the IRP
2799 demonstrated that the "less hedged portfolio shows a wider distribution of

²⁶ Direct Testimony of Lori Schell, Phase 1, Docket No. 09-035-15 (November 16, 2009).

²⁷ Direct Testimony of Lori Schell, Phase 2, Docket No. 09-035-15 (June 10, 2010).

2800 outcomes representing a higher risk to price changes. Similarly, the more hedged
2801 portfolio shows a narrower distribution.” Second, the analysis showed that “[t]he
2802 ‘hedge only power’ portfolio shows a much wider distribution due to the severe
2803 reduction in the natural offset between power and natural gas in the reference
2804 portfolio. The ‘hedge only natural gas’ has a similar distribution.”²⁸

2805 **Historic Benefits of Hedging in Company’s Net Power Costs**

2806 **Q. Have you analyzed the historic impact of the Company’s hedging program**
2807 **on NPC in Utah rates?**

2808 A. Yes. I have prepared Exhibit RMP___(GND-6R) which sets forth the impact of
2809 the Company’s hedging program on NPC in Utah rates.

2810 **Q. Please summarize the results of your analysis.**

2811 A. From March 1, 2005, when rates from Docket 04-035-42 went into effect through
2812 end of September 2011 when rates from this case will become effective,
2813 customers will have received \$149 million in lower system NPC as a result of the
2814 Company’s hedging program.

2815 **Q. What is the benefit of the Company’s hedging program now reflected in Utah**
2816 **rates?**

2817 A. By virtue of the significant hedging benefits reflected in the Company’s 2009
2818 GRC, current rates (rates in effect between February 18, 2010 and the end of
2819 September 2011) reflect a total benefit of \$192 million in system NPC reductions.
2820 These benefits were achieved under the same risk management policy and
2821 hedging program applicable to the hedges for the test period in this case. It would

²⁸ Docket No. 11-2035-01, PacifiCorp 2011 IRP, Appendix F at 165 (March 31, 2011).

2822 be unfair to accept the substantial benefits of the hedging program in 2010 and
2823 2011, and then disallow the costs of it going forward when nothing material has
2824 changed in the Company's approach or circumstances.

2825 **Q. Did the hedging program mitigate the Company's exposure to market price**
2826 **fluctuations?**

2827 A. Yes. Prior to the EBA, the Company was exposed to all of the risk of market
2828 fluctuations between rate cases. The Company's hedging program has helped
2829 mitigate this position and maintain the Company's financial stability. Exhibit
2830 RMP___(GND-6R) shows that between March 1, 2005 and September 2011, the
2831 Company's hedging program resulted in a net savings of \$406.5 million over an
2832 unhedged position.

2833 **Q. If the Company had restricted its hedging volumes to 75 percent and 66**
2834 **percent as proposed by UAE and UIEC, respectively, would customers have**
2835 **been better off in the past?**

2836 A. No. Had the Company imposed the upper limits UAE and UIEC now recommend,
2837 customers would have been exposed to higher NPC and market volatility over the
2838 past six years. Under UAE's proposal, they would have received only 75 percent
2839 of the realized benefits (\$112 million, a reduction of \$37 million); under UIEC's
2840 proposal, they would have received only 66 percent of the realized benefits (\$98
2841 million, a reduction of \$51 million).

2842 **Q. On a year-by-year basis, do the results of the hedging program vary?**

2843 A. Yes. In the various GRID studies since the Company's 2004 general rate case, the
2844 results of the Company's hedging program have produced results that lower NPC

2845 by as much as \$119 million and increase NPC by up to \$38 million over a 12-
2846 month test period.

2847 **Q. How do customers benefit from the Company's hedge program in years**
2848 **where hedges are unfavorable, such as in the test year?**

2849 A. The purpose of the Company's hedge program is to reduce the volatility of NPC.
2850 Absent the Company's hedge program, NPC would be subject to potentially large
2851 swings from year to year depending upon the volatility of the spot market.

2852 **Q. Have parties previously claimed that the Company's risk management policy**
2853 **and hedge program were imprudent when the hedges have increased NPC?**

2854 A. No. The Company's hedges increased NPC in the Company's 2004 and 2006
2855 general rate cases. No party claimed that these losses were evidence of
2856 imprudence. Losses and gains will always co-exist in a hedging program; while
2857 hedges are unfavorable in the test period, the hedges in the previous rate case
2858 were extremely favorable.

2859 **Q. Please summarize your recommendations on hedging.**

2860 A. I recommend that the Commission reject the arguments raised by the parties I
2861 rebut and enter a finding that the Company's hedging program is prudent and the
2862 associated costs are reasonable. My testimony and the analytical evidence I
2863 sponsor demonstrates that the Company's hedging program has reduced the
2864 volatility of NPC and that customers have received NPC benefits as a result of the
2865 Company's hedging program.

2866 **Q. Does this conclude your rebuttal testimony?**

2867 A. Yes.