

REDACTED
Rocky Mountain Power
Docket No. 10-035-124
Witness: Steven R. McDougal

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Redacted Rebuttal Testimony of Steven R. McDougal

Revenue Requirement

June 2011

1 **Q. Please state your name and business address.**

2 A. My name is Steven R. McDougal and my business address is 201 South Main,
3 Suite 2300, Salt Lake City, Utah, 84111.

4 **Q. Are you the same Steven R. McDougal who has previously filed testimony in**
5 **this proceeding?**

6 A. Yes.

7 **Purpose of Testimony**

8 **Q. What is the purpose of your revenue requirement rebuttal testimony in this**
9 **proceeding?**

10 A. The purpose of my revenue requirement rebuttal testimony is to provide a revised
11 calculation of the Company's Utah-allocated revenue requirement in this case,
12 including adjustments made to the original filing by the Company and also
13 adjustments that address items raised in the direct testimony of intervening parties
14 including the Division of Public Utilities ("DPU"), the Office of Consumer
15 Services ("OCS"), Utah Association of Energy Users Intervention Group
16 ("UAE") and the Utah Industrial Energy Consumers ("UIEC"). The revised
17 revenue requirement incorporates adjustments addressed in my rebuttal testimony
18 as well as the rebuttal testimony of other Company witnesses. I also respond to
19 various issues raised in the direct revenue requirement testimony sponsored by the
20 DPU, OCS, UAE and UIEC that the Company does not agree with and has not
21 adopted in its revised revenue requirement. The Company believes these disputed
22 adjustments should not be adopted by the Utah Public Service Commission in this
23 case.

24 **Revised Revenue Requirement**

25 **Q. Have you recalculated revenue requirement for the test year?**

26 A. Yes. The Company has adopted a number of adjustments related to issues
27 identified by the Company and intervening parties in this case, reducing the
28 overall requested price change from \$232.4 million to \$188.1 million. The
29 revised calculation is presented in exhibits accompanying my testimony. Exhibit
30 RMP__(SRM-1R) shows a summary of the adjustments made to the revenue
31 requirement originally requested by the Company. Exhibit RMP__(SRM-2R) is
32 a revised Exhibit RMP__(SRM-3) from the Company's original filing with
33 updated Tabs 1, 2, 9, 10, and 11 and includes a new Tab 12 containing supporting
34 detail for each new adjustment made to the Company's filing.

35 **Q. Please identify the adjustments made to arrive at the revised overall revenue**
36 **increase.**

37 A. The following new adjustments have been made to the Company's revenue
38 requirement. Each is described further in my testimony.

Utah GRC Rebuttal - Company Position

Filed Results - Revised Protocol	\$ 232,416,309
Move to Rolled In	(15,013,228)
Adopt 2010 Protocol Agreement / State Income Taxes	(3,437,057)
Cost of Debt	(2,635,407)
12.1 SO2 Emission Allowances	102,511
12.2 REC Revenue	(18,516,752)
12.3 Joint Use Revenue	199,271
12.4 Outside Services and Miscellaneous Expense	(373,190)
12.5 Incremental O&M	(436,859)
12.6 Generation Overhaul	363,365
12.7 TRiP Labor Savings	(72,810)
12.8 Reduction to Salaries/Wages	(1,954,917)
12.9 Incentive Compensation	(1,134,813)
12.10 Pension and Post Retirement Benefits	(2,969,163)
12.11 Remove Challenge Grants	(208,064)
12.12 Incremental Bonus Depreciation Update	9,313,978
12.13 Pro Forma Plant Additions and Retirements	(6,168,127)
12.14 Misc Asset Removal	(497,667)
12.15 Bridger and Trapper Mines	37,044
12.16 Depreciation Expense Update	(866,989)
12.17 Depreciation Reserve Update	5,454,316
12.18 Plant Related Tax Update	(888,568)
12.19 Correct Deferred Tax Allocation Factors	(112,234)
12.20 Cottonwood Coal Lease	1,100,556
12.21 Powerdale Decommissioning	(369,612)
12.22 Net Power Costs	(5,274,617)
Rebuttal Results - 2010 Protocol	<u>\$ 188,057,278</u>

39 **Inter-Jurisdictional Allocation**

40 **Q. The DPU, OCS, and UAE each proposed that Utah revenue requirement in**
41 **this case be determined using the Rolled In allocation method. Do you**
42 **agree?**

43 **A. The Company does not object to the proposal made by the DPU, OCS, and UAE.**

44 However, since filing their direct testimonies, these parties have entered into an
45 agreement with the Company regarding implementation of the 2010 Protocol that
46 is pending Commission review and approval. The Company's rebuttal filing is
47 prepared based on the 2010 Protocol agreement, which directs that the Hydro
48 Endowment and Klamath Surcharge adjustments are deemed to net to zero and is
49 the economic equivalent of Rolled In. Consequently, the results displayed on Tab
50 2 (2010 Protocol) and Tab 9 (Rolled In) of Exhibit RMP__(SRM-2R) are
51 identical. As shown in the table of adjustments above, the originally filed revenue
52 requirement is reduced approximately \$15 million due to the change in allocation
53 method. In addition, as part of the 2010 Protocol agreement the calculation of
54 state income taxes under all allocation methods is changed to be based on the
55 blended statutory tax rate rather than allocated on the Income Before Tax ("IBT")
56 factor. This change reduces the filed revenue requirement by an additional \$3.4
57 million; additional details are provided later in my testimony. The impact of each
58 of the remaining adjustments comprising the Company's rebuttal revenue
59 requirement is stated based on the 2010 Protocol allocation method, which as
60 described above is the same as Rolled In.

61 **Q. What is the status of the Company's application filed in Docket No. 02-035-**
62 **04 to amend the Revised Protocol?**

63 A. After filing this general rate case, the Company has continued to work with
64 interested parties in hopes of reaching a settlement related to the 2010 Protocol.
65 On June 27, 2011, the Company filed with the Commission an agreement reached
66 between the Company and the DPU, OCS and UAE. The Commission had

67 previously suspended the procedural schedule in that docket in order for parties to
68 continue discussions. The agreement is now pending Commission review and
69 approval.

70 **Q. Is using the 2010 Protocol agreement to set rates in this case consistent with**
71 **Commission orders in Docket No. 09-035-23?**

72 A. Yes. In Docket No. 09-035-23 the Commission issued an order stating,
73 “Although constrained by the time remaining in this docket, we intend to have
74 inter-jurisdictional allocation issues addressed and the reasonableness of any
75 allocation established prior to our approval of any future change in RMP’s rates.”
76 Parties to the current rate case have provided substantial testimony supporting the
77 use of a Rolled In allocation as a benchmark against which the reasonableness of
78 any allocation method is to be established. Rolled In and 2010 Protocol produce
79 identical results once the ECD adjustments are eliminated.

80 **Q. In your direct testimony you pointed out that discussions were also occurring**
81 **regarding the jurisdictional treatment of the Company’s Class 1 demand side**
82 **management (“DSM”) programs. Is a change now required to the**
83 **Company’s filing in this case?**

84 A. No. A consensus has not been reached among participants in those discussions,
85 and in the absence of any agreement, the Company is not proposing to change the
86 allocation treatment of Class 1 DSM programs in this case. The costs and
87 benefits of these programs in this case remain situs assigned to the state in which
88 the program originates.

89 **Q. Please explain in more detail the change to the calculation of state income**
90 **taxes.**

91 A. In the Company's original filing state income taxes were allocated among all
92 jurisdictions using IBT allocation factor as prescribed in the Revised Protocol
93 allocation method. While this is conceptually consistent with the approved
94 Revised Protocol and current practice under the Rolled In method, the resulting
95 allocation of state income taxes to Utah may not yield intuitive results. When
96 allocating income across multiple jurisdictions it is preferable to directly calculate
97 income tax responsibility based on the income attributable to each jurisdiction and
98 doing so avoids the anomalous results seen in this case as well as previous cases¹
99 in Utah.

100 **Q. What do you mean that the results in this case are anomalous?**

101 A. In the Company's revenue requirement model, the test period results feed into the
102 calculation of the inter-jurisdictional allocation factors. Based on allocated taxable
103 income in the originally filed case, Utah's Rolled In IBT factor is 58.96 percent
104 (compared to an SG factor of 43.28 percent) and the resulting implied tax rate is
105 2.75 percent, well below the blended statutory rate of 4.54 percent. Because
106 taxable income and the resulting state income taxes are negative, the lower than
107 expected implied tax rate signifies Utah revenue requirement would be overstated
108 unless the issue is corrected.

109 **Q. What is the impact of the correction to the state income tax calculation?**

110 A. If the correction is made once the change to Rolled In allocation is implemented,

¹ The Company has addressed the allocation of state income taxes in Docket Nos. 08-035-38, 10-035-13, and 10-035-89.

111 it reduces revenue requirement by approximately \$3.4 million. The table below
 112 shows the detailed calculation of Utah-allocated taxable income the state income
 113 taxes expense before and after the correction is made.

Utah Allocated Income Tax Calculation - Rolled In Method

	As Filed	Corrected
	State Income Tax Allocated On IBT Factor	State Income Tax Allocated Calculated Using Statutory Rate
Calculation of Taxable Income:		
Operating Revenues	1,993,639,617	1,993,639,617
Operating Deductions:		
O & M Expenses	1,305,871,785	1,305,871,785
Depreciation Expense	233,031,726	233,031,726
Amortization Expense	20,477,315	20,477,315
Taxes Other Than Income	54,840,527	54,840,527
Interest & Dividends (AFUDC-Equity)	(17,946,961)	(17,946,961)
Misc Revenue & Expense	(2,527,310)	(2,527,310)
Total Operating Deductions	1,593,747,081	1,593,747,081
Other Deductions:		
Interest Deductions	152,738,934	152,738,029
Interest on PCRBS	-	-
Schedule M Adjustments	(429,766,212)	(429,766,212)
Income Before State Taxes	(182,612,610)	(182,611,705)
State Income Taxes	(5,368,321)	(8,635,365)
Total Taxable Income	(177,244,289)	(173,976,340)
Tax Rate	35.0%	35.0%
Federal Income Tax - Calculated	(62,035,501)	(60,891,719)
State Income Taxes		
Calculated	(5,023,528)	(8,290,571)
Production Tax Credits	(344,794)	(344,794)
Total State Tax Expense	(5,368,321)	(8,635,365)
<i>Implied State Income Tax Rate</i>	<i>2.75%</i>	<i>4.54%</i>

114 **Q. Has the Company made similar adjustments in previous cases?**

115 A. Yes. Most recently, in Docket No. 10-035-89 (“MPA II”) the incremental
 116 revenue requirement of the MPA II projects was calculated using 4.54 percent of

117 taxable income for the state income tax expense rather than relying on the IBT
118 factor allocation.

119 **Q. The state tax correction is one that affects multiple jurisdictions; has it been**
120 **addressed in the Multi State Process arena?**

121 A. Yes. The 2010 Protocol prescribes that state income taxes be computed using the
122 weighted statutory rate calculation. The Company's original filing already
123 included this calculation under the 2010 Protocol allocation methodology.

124 **Q. Have any other issues related to inter-jurisdictional allocations been raised**
125 **by parties in this proceeding?**

126 A. Yes. UIEC witness Mr. Dennis E. Peseau proposes to depart from the accepted
127 allocation of transmission plant in a thinly veiled attempt to disallow a portion of
128 the Populus to Terminal transmission line. The Company does not agree with this
129 treatment and has not adopted this adjustment. Mr. Peseau argues that the
130 Company's investment in the Populus to Terminal line will only be able to
131 operate for the benefit of retail customers at 50 percent of ultimate capacity and
132 that the remaining portion should be 'allocated' away from retail customers
133 during the Test Period. Company witness Mr. John Cupparo provides rebuttal
134 testimony clearly demonstrating the prudence of the Populus to Terminal line,
135 including the need for the investment and the benefits to the Company's retail
136 customers. Mr. Cupparo's testimony renders Mr. Peseau's adjustment
137 unnecessary and supports the allocation methodology currently accepted in Utah
138 of allocating transmission plant to each the Company's retail jurisdictions, offset
139 by a revenue credit for third party use that is similarly allocated across retail

140 jurisdictions. Furthermore, inter-jurisdictional allocation of the Company's
141 transmission facilities has been studied extensively by parties in Utah, Oregon,
142 Wyoming, and Idaho, resulting in agreed upon allocation methodologies utilized
143 in recent general rate cases in each of those states.

144 **Q. Did Mr. Peseau misconstrue the inter-jurisdictional allocation of the Populus**
145 **to Ben Lomond segment of this line in Docket No. 10-035-89?**

146 A. Yes. On page 16 of his testimony, Mr. Peseau states, "As I understand it, the
147 Company offered ... to give Utah a transmission revenue credit of 20% of the
148 bundled revenue associated with off-system sales of power." He also references
149 the Company's response to UIEC data request 3.39 in the current docket as
150 confirmation of his statement.

151 Mr. Peseau's interpretation of the issue is incorrect and his application of
152 it in the revenue requirement phase of this case is inappropriate. Revenue
153 requirement of the transmission assets in Docket 10-035-89 was computed in
154 exactly the same manner as done in the current case, i.e. 100 percent of the project
155 costs were allocated among the Company's six states while system-wide sales for
156 resale is included as an offset to revenue requirement and is similarly allocated
157 amongst all six jurisdictions. The response to UIEC 3.39 confirms that Mr.
158 Peseau is confusing inter-jurisdictional cost allocation to the functionalization of
159 sales for resale for purposes of class cost of service. UIEC 3.39 states,

160 In Docket No. 10-035-89, the cost of service (COS) study showed
161 a portion of Account 447 – Sales for Resale (approximately 20%)
162 functionalized to Transmission. In the current proceeding, Exhibit
163 RMP__(CCP-4) shows 0% of Account 447 functionalized to
164 Transmission in order to be consistent with the Jurisdictional
165 Allocation Model (JAM).

166 In DPU 47.10 the Company further clarified the response stating,

167 In the class cost of service studies filed in Docket No. 10-035-89
168 Account 447 – Sales for Resale is functionalized 79.5355% to the
169 Generation function and 20.4665% to the Transmission function.
170 In the current case, this has been revised to 100% Generation and
171 0% Transmission, as explained in response to UIEC 3.39. In both
172 cases, retail ratepayers were credited with the full amount of the
173 wholesale sales revenues.

174 **Q. Have other states served by PacifiCorp approved ratemaking treatment of**
175 **Populus to Terminal as proposed by the Company in this case, including the**
176 **inter-jurisdictional allocation?**

177 A. Yes. The Wyoming Public Service Commission recently approved a stipulation
178 resolving the Company’s general rate case in Docket No. 20000-384-ER-10. The
179 Populus to Terminal revenue requirement in that case was calculated identically
180 to the Company’s Utah filings, and the stipulation explicitly recognizes the
181 appropriateness of including the Populus to Terminal investment in retail
182 customers’ rates.

183 **Adjustments Adopted by the Company**

184 **Cost of Capital**

185 **Q. Does the Company’s revised revenue requirement incorporate the cost of**
186 **debt supported by Company witness Mr. Bruce N. Williams in his cost of**
187 **capital rebuttal testimony?**

188 A. Yes. As described by Mr. Williams, the Company has reduced the cost of debt in
189 the Test Period from 5.81 percent to 5.71 percent, lowering revenue requirement
190 by approximately \$2.6 million.

191 **Q. Did the Company alter its requested return on equity in this case?**

192 A. No. As supported by the cost of capital rebuttal testimony of Company witness

193 Dr. Samuel C. Hadaway, the Company's revenue requirement continues to be
194 calculated based on a 10.5 percent return on equity.

195 **SO₂ Emission Allowance Revenue**

196 **Q. Please describe the adjustment to revenue from the sale of SO₂ emission**
197 **allowances.**

198 A. Adjustment 12.1 in Exhibit RMP__(SRM-2R) reduces the amortization of SO₂
199 emission allowance sales by \$100,000 on a Utah allocated basis, pursuant to the
200 settlement stipulation reached in Docket No. 10-035-12 ("MPA I") and approved
201 by the Commission on June 15, 2010. In that settlement stipulation, parties
202 agreed that the projected net revenue requirement impact of the projects included
203 in MPA I included an annual credit of \$200,000 (Utah-allocated) for incremental
204 SO₂ emission allowance sales. In paragraph 11 of the stipulation the parties
205 agreed that a pro rata share of this value (based on the length of time it was
206 included as an offset to the regulatory asset accrual resulting from the settlement
207 stipulation) will be excluded from the amount that would otherwise be used to
208 establish the four-year amortization of SO₂ emission allowance sales revenue for
209 general rate case purposes. The regulatory asset accrual established in the MPA I
210 settlement was in place from July 1, 2010, through December 31, 2010;
211 consequently, the Company may properly exclude \$100,000 on a Utah-allocated
212 basis from the amortization of SO₂ emission allowance sales in this case.

213 **Q. Was this accounted for in the Company's direct filing in this case?**

214 A. No. The Company inadvertently did not account for this settlement item in its
215 direct filing.

216 **Renewable Energy Credits**

217 **Q. Please explain the adjustment to revenue from the sale of renewable energy**
218 **credits (“RECs”).**

219 A. As proposed in the direct testimony of Company witness Mr. Stefan Bird, the
220 Company has updated the REC revenue forecast for the Test Period to incorporate
221 successfully reaching a deal to sell additional RECs to NV Energy. The Company
222 provided an updated REC revenue forecast in the first supplemental response to
223 DPU data request 10.52. An even more recent forecast of known transactions was
224 provided in response to UAE data request 11.1.² The total revenue and volume
225 from known transactions in the Test Period is the same in both DPU 10.52 1st
226 Supplemental and UAE 11.1, but there is a slight difference in the resource mix
227 forecasted to be used to meet the contractual deliveries. The Company’s rebuttal
228 adjustment 12.2 in Exhibit RMP__(SRM-2R) incorporates the updated forecast of
229 known REC sales transactions, provided in UAE 11.1. Assumptions regarding the
230 remaining volume of RECs to be sold and the price realized for these additional
231 forecasted sales remain unchanged from the Company’s original filing. The
232 Company’s rebuttal adjustment is equal to the adjustment made by DPU witness
233 Ms. Brenda Salter in her primary proposal regarding REC revenue, and it reduces
234 revenue requirement in the rebuttal case by approximately \$18.5 million
235 compared to the Company’s original filing. OCS witness Ms. Donna Ramas and
236 UAE witness Mr. Kevin Higgins also incorporated the revised forecast from DPU
237 10.52 1st Supplemental into their proposed revenue requirement.

² The 1st supplemental response to DPU 10.52 provided a full recalculation of the REC revenue adjustment based on the revised Test Period forecast while the response to UAE 11.1 only updated the known REC transactions.

238 **Q. In addition to the known transactions, various intervening parties also**
239 **proposed that the price assumed to be realized for RECs sold be increased**
240 **substantially. Has the Company adopted this proposal?**

241 A. No. The Company does not agree that the price assumed for REC transactions
242 beyond those currently known should be increased in this case. Company witness
243 Stefan Bird provides more details regarding REC sales transactions and the
244 appropriate volumes and prices that should be included in the Test Period.

245 **Q. Ms. Salter and Ms. Ramas also proposed mechanisms going forward to**
246 **account for any differences between actual REC sales and the level included**
247 **in customers' rates from this case. Is the Company opposed to such a**
248 **mechanism?**

249 A. No. The Company believes it is appropriate to track difference between the level
250 of REC revenue in customer rates resulting from this case and actual REC
251 revenue for later refund to or collection from customers. I will discuss this
252 concept in more detail later in my testimony. I will also discuss the Company's
253 position regarding REC revenue that has been deferred on the Company's books
254 since February 22, 2010.

255 **Joint Use Revenue**

256 **Q. Please explain the adjustment to joint use revenue.**

257 A. Rebuttal Adjustment 12.3 in Exhibit RMP__(SRM-2R) simply reverses the
258 original Adjustment 3.5, Joint Use Revenue, included in Exhibit RMP__(SRM-3)
259 in the Company's original filing, consistent with the Commission's order on
260 URTA Motion to Dismiss Pole Attachment Issues or for Alternative Relief issued

261 in this docket on June 1, 2011. In my supplemental direct testimony on pole
262 attachments filed June 8, 2011, I indicated the Company would withdraw
263 Adjustment 3.5.

264 **Outside Services and Miscellaneous Expense**

265 **Q. Do you agree with the removals of outside services and miscellaneous**
266 **expenses recommended by Ms. Ramas in her testimony?**

267 A. In part. Ms. Ramas proposes to remove nine items included in expenses for
268 outside services and two items booked to miscellaneous expense. The Company
269 agrees that all but two of these items should be removed from the Test Period.
270 Adjustment 12.4 in Exhibit RMP__(SRM-2R) removes these seven items from
271 outside services proposed in Ms. Ramas' adjustment that the Company agrees
272 with. Both items that should not be removed are payments to Tegarden &
273 Associates, Inc. in connection with appeals of property tax assessments in Idaho
274 and Montana.

275 **Q. Please explain why the payments to Tegarden & Associates, Inc.**
276 **(“Tegarden”) should not be removed from the Test Period.**

277 A. Ms. Ramas first removes \$44,562 related to charges from Tegarden because she
278 claims it relates to out of period costs that were incurred prior to the base period
279 in this case. The invoice for these charges was accrued in June 2009 to expense
280 in Account 530007, Accounting/Audit/Technical Services. This accrual was
281 reversed in July 2009, offsetting the expense charged when the payment was
282 made. When the accrual and reversal are considered, this expense is never in the
283 Test Period. Next, Ms. Ramas removes \$54,929 related to additional charges from

284 Tegarden claiming the costs “are non-recurring in nature and associated with
285 appraisal values as of 2006 and 2007” for Company property in Montana.

286 The Company is continually involved in litigated ad valorem proceedings,
287 requiring valuation experts to support hearings to challenge the amount of
288 property taxes paid by the Company. Perhaps more importantly the Company’s
289 challenges to property tax assessments influence the methodology for computing
290 the property taxes owed now and in the future. Successful challenges to the
291 methodologies used by various taxing jurisdictions carry over into future years
292 and ultimately benefit all of the Company’s customers by reducing subsequent
293 property tax assessments. The assertion that these expenses are out of period and
294 non-recurring is not correct.

295 **Incremental Generation O&M**

296 **Q. Do you agree with the adjustment proposed by OCS witness Ms. Ramas to**
297 **reduce incremental generation O&M?**

298 A. Yes. Ms. Ramas proposes to reduce the Company’s original adjustment for
299 incremental generation O&M expense for two items based on the Company’s
300 response to OCS 15.6 and OCS 15.10. First, she removes a double count of
301 actual operating costs related to the Dunlap I wind facility, reducing O&M by
302 \$178 thousand. Next, she reduces O&M for the Lake Side facility by \$827
303 thousand because after the Company’s case was prepared the long-term gas
304 turbine parts and services contract with Siemens was renegotiated with a higher
305 portion of the costs being capitalized. The Company has incorporated both of
306 these items in its adjustment 12.5 in Exhibit RMP__(SRM-2R).

307 **Generation Overhaul Expense**

308 **Q. Please describe the adjustment to generation overhaul expense.**

309 A. Adjustment 12.6 in Exhibit RMP__(SRM-2R) to generation overhaul expense
310 incorporates two changes from the Company's original filing. First, the Company
311 is adopting the adjustment proposed by Dr. Artie Powell to use constant dollars in
312 computing the four year average for generation overhauls. Second, the Company
313 is incorporating the adjustment proposed by Ms. Ramas to update the spring 2011
314 Lake Side overhaul expense and the removal of the Little Mountain steam plant.

315 **Q. Why is the Company adopting Dr. Powell's adjustment using constant**
316 **dollars?**

317 A. Dr. Powell correctly points out that from an economic standpoint, averaging
318 dollars from multiple years requires the dollars to be stated on a consistent basis
319 prior to averaging. The Company agrees with his statement that: "economic
320 theory suggests that in order to compare two values separated by time, the values
321 need to have a common monetary base: the values should be expressed in real
322 terms."³

323 **Q. Can you provide a simple example to further support the concept of using**
324 **constant dollars when computing an average expense over time?**

325 A. Yes. As I mentioned in my direct testimony on revenue requirement, the purpose
326 of averaging is to adjust for uneven costs, not to adjust for inflation. A simple
327 example below shows the impact of averaging, assuming a 2.5 percent inflation
328 rate, a \$100 amount in year one, and a four year average of years one through four
329 used to project costs in year five. Using this assumption, Example 1 shows the

³ Direct testimony of Dr. Artie Powell, page 28, lines 475 – 477.

330 impact without adjusting for inflation, and Example 2 shows the impact when
 331 years one through four are stated in real dollars.

332 As shown in the first example, with no escalation to account for inflation a
 333 four year average of costs is \$103.8, much less than the projected costs in year
 334 five, resulting in an expense level that is 2.5 years old compared to the current
 335 expenses. In Example 2, the average is equal to the year five amount resulting in
 336 an accurate forecast.

Example 1		Example 2			
Year	Amount	Year	Amount	Escalation	Adjusted Amount
1	\$ 100.0	1	\$ 100.0	1.104	\$ 110.4
2	102.5	2	102.5	1.077	110.4
3	105.1	3	105.1	1.051	110.4
4	107.7	4	107.7	1.025	110.4
5	110.4	5	110.4		

Avg. \$103.8

Avg. \$110.4

337 **Q. Please describe the adjustment adopted with regards to the spring 2011 Lake**
 338 **Side overhaul and for the removal of the Little Mountain steam plant.**

339 A. As proposed by Ms. Ramas the spring 2011 Lake Side overhaul was updated to
 340 reflect the actual overhaul expense incurred, and the Little Mountain steam plant
 341 overhaul expense was removed because the Little Mountain steam plant is
 342 expected to be retired in February 2012.

343 **TRiP Labor Savings**

344 **Q. Please briefly describe OCS Witness Ms. Ramas' TRiP Energy Trading**
 345 **computer system labor cost savings adjustment.**

346 A. Ms. Ramas proposes to include some labor savings into the case associated with
 347 the implementation of the commercial and trading TRiP Energy Trading System

348 which was placed into service February 1, 2011. The Company's cost benefit
349 analysis mentioned projected reductions in full-time equivalent ("FTE") employee
350 positions that will result from implementation of the project. Exhibit OCS 3.16
351 reduces labor expense for six full-time equivalents and includes labor savings of
352 \$900,000 (6 FTE's times \$150,000 each) based on high-level estimates used in
353 the initial analysis of the project.

354 **Q. Does the Company agree that an adjustment to labor expense is needed as a**
355 **result of the TRiP implementation?**

356 A. Yes. The Company agrees that an adjustment is needed to reflect labor savings in
357 the Test Period resulting from implementation of the TRiP system, but the
358 required adjustment is smaller than the adjustment proposed by Ms. Ramas. There
359 has been a reduction in employees as a result of the implementation of the TRiP
360 system; however, only some of the positions that were eliminated were still on the
361 payroll during the base period. The Company has calculated the labor expenses
362 that need to be removed from this case by looking at the specific jobs eliminated,
363 and the number of months an employee was working in the position during the
364 base period. Specifically, three positions in the information technology
365 department were eliminated in 2007, one position in the finance department was
366 eliminated in 2008, and two positions in the commercial and trading department
367 were eliminated in 2010. Based on this calculation, costs for 1.67 FTEs that were
368 eliminated by the TRiP system are included in the base period in this case and
369 should be removed. The remaining positions were eliminated prior to the base
370 period. Each of the reductions occurred well ahead of the targeted labor savings

371 timeline of six months after the implementation of the new system. Adjustment
372 12.7 in Exhibit RMP__(SRM-2R) reduces revenue requirement by approximately
373 \$173 thousand on a total Company basis or \$73 thousand on a Utah allocated
374 basis.

375 **Reduction to Salaries**

376 **Q. Please briefly describe OCS Witness Ramas' reduction to salaries and wage**
377 **adjustment.**

378 A. Ms. Ramas proposes to reduce Test Period salaries and wage expense by 1.27
379 percent which represents the three year comparison of actual and projected
380 regular, overtime, and premium pay from the last three rate cases. Exhibit OCS
381 3.15 reduces labor expense by approximately \$6.3 million on a total Company
382 basis. Ms. Ramas' adjustment reduces revenue requirement by approximately
383 \$1.9 million on a Utah allocated basis.

384 **Q. Is the Company accepting Ms. Ramas' adjustment in this case?**

385 A. Yes. Although the Company does not conceptually agree with the adjustment, the
386 Company has adopted it for this case in Adjustment 12.8 of Exhibit
387 RMP__(SRM-2R). Please refer to the rebuttal testimony of Company witness
388 Mr. Erich D. Wilson as he describes the Company's position on Ms. Ramas'
389 salaries and wages expense adjustment and why the Company accepts her
390 adjustment.

391 **Q. Will the Company be making this adjustment in future cases?**

392 A. No. The Company believes that the best method for calculating salary and wage
393 expense is using actual wages in the base period and then escalating those wages

394 with known union contract increases or target increases when known contract
395 information is not available.

396 **Incentive Compensation**

397 **Q. What level of incentive compensation did the Company include in this case?**

398 A. In its original filing, the Company included annual incentive plan compensation
399 costs of approximately \$33.7 million which is the average of the target payout
400 levels expected in 2011 and 2012.

401 **Q. Did the OCS and DPU propose alternative adjustments for incentive
402 compensation in this case?**

403 A. Yes.

404 **Q. Please briefly describe OCS witness Ms. Ramas' adjustment to incentive
405 compensation.**

406 A. Ms. Ramas proposes to adjust incentive compensation to a two year average of
407 2009 and 2010 actual payout escalated for the January 2011 non-union labor
408 increase and 50 percent of the January 2012 non-union labor increase. Her
409 adjustment in Exhibit OCS 3.17 reduces incentive expense included in the case to
410 \$29.5 million or a reduction of approximately \$1.2 million on a Utah allocated
411 basis. Please refer to the rebuttal testimony of Company witness Mr. Wilson as he
412 describes the Company's position on Ms. Ramas' incentive compensation
413 adjustment.

414 **Q. Please briefly describe DPU witness Mr. Mark E. Garrett adjustment to
415 incentive compensation.**

416 A. Mr. Garrett proposes to adjust incentive compensation to the three year average of

417 2008, 2009, and 2010 actual payout. His adjustment in Exhibit DPU 10.3 reduces
418 incentive expense included in the case to approximately \$28.8 million or a
419 reduction of approximately \$1.4 million on a Utah allocated basis. Please refer to
420 the rebuttal testimony of Company witness Mr. Wilson as he describes the
421 Company's position on Mr. Garrett's incentive compensation adjustment.

422 **Q. What adjustment does the Company propose to the level of incentive**
423 **compensation?**

424 A. In this case, the Company accepts an averaging of incentive compensation
425 expense. The concept of averaging of certain expenses that tend to fluctuate from
426 year to year is an acceptable approach in rate making in certain situations. While
427 the OCS approach of using only two data points (2009 and 2010) is insufficient
428 for a proper average, the Company supports a three year historical average
429 calculated by comparing the actual "at-risk" incentive compensation payout as
430 compared to payroll (regular time, overtime, and premium pay) for years 2008
431 through 2010, multiplied by Test Period wages. The "at-risk" incentive payout
432 percentage of payroll is calculated in this case to be 14.90 percent as shown in the
433 following table.

Year	Payroll	Incentive	Paid "At-Risk" percent
2008	\$190,502,520	\$31,142,229	16.35%
2009	200,112,042	29,876,294	14.93%
2010	197,330,060	26,606,117	13.48%
Total	\$587,944,622	\$87,624,640	14.90%

434 Using this approach results in a test year incentive expense of
435 approximately \$30.1 million and is included in Adjustment 12.9 in Exhibit

436 RMP___(SRM-2R). The Company's proposal reduces revenue requirement by
437 approximately \$2.7 million on a total Company basis or approximately \$1.1
438 million on a Utah allocated basis. The Company's adjustment is similar in
439 concept to both Ms. Ramas and Mr. Garrett in that it allows for an averaging. The
440 Company believes a three year average is more appropriate and is consistent with
441 other averages used in the Test Period for items such as insurance expense. The
442 Company's approach differs from Ms. Ramas and Mr. Garrett adjustment in that
443 it applies the average payout rate to the adjusted wages in the Test Period.

444 **Pension Expense**

445 **Q. What level of pension expense did the Company include in this case?**

446 A. In its original filing, the Company included pension expense of \$27.8 million for
447 the PacifiCorp retirement plan and \$13.85 million for the Local 57 contribution
448 amount for a total pension expense of approximately \$41.65 million which is the
449 average of the Company's actuarial projections for 2011 and 2012. These were
450 the most current figures available at the time of filing.

451 **Q. Did the OCS propose alternative adjustments for pension expense in this**
452 **case?**

453 A. Yes. Ms. Ramas proposes to adjust the PacifiCorp retirement plan expense for
454 2011 to the actual amount of \$ 24.0 million and then further adjusting this amount
455 downward to \$21.5 million by increasing the long-term rate of return assumption
456 by 25 basis points. Ms. Ramas also proposes to adjust the Local 57 contribution
457 by annualizing the January to June 2011 actual amount of \$6.4 million to \$12.8
458 million for the Test Period. Please refer to the rebuttal testimony of Company

459 witness Mr. Williams as he describes the Company's position on Ms. Ramas'
460 pension expense adjustment.

461 **Q. What adjustment does the Company propose to the level of pension expense?**

462 A. The Company proposes to update the pension expense and post retirement benefit
463 expense to reflect the average of calendar year 2011 actual expense and updated
464 calendar year 2012 projections. The Company proposes a further adjustment to
465 Local 57 retirement expense to reflect updated expected expense during the Test
466 Period equal to cash contributions (\$18.5 million) less amount to be reimbursed
467 by the union beginning in 2015 (\$5.9 million). These changes result in a Test
468 Period pension expense of \$33.9 million and post retirement benefit expense of
469 \$16.95 million and are included in Adjustment 12.10 in Exhibit RMP____(SRM-
470 2R). The Company's proposal reduces revenue requirement by approximately
471 \$3.0 million on a Utah allocated basis. Adjustment 12.10 in Exhibit
472 RMP____(SRM-2R) is consistent with the testimony of Mr. Williams.

473 **Challenge Grants & Rent Subsidy**

474 **Q. Please describe the adjustments proposed by OCS witness Ms. Ramas and**
475 **DPU witness Ms. Salter with regards to challenge grants.**

476 A. The Company sub-lets office space in the One Utah Center to Economic
477 Development Corporation of Utah ("EDCU") and the Utah Sports Commission
478 for \$1 per month rent plus operating expenses. The resulting subsidy is booked as
479 a challenge grant to these organizations amounting to approximately \$163
480 thousand in the Test Period (including escalation). Both Ms. Ramas and Ms.
481 Salter propose disallowing rent contributions made by the Company to the EDCU

482 and the Utah Sports Commission. Ms. Salter also recommends disallowance of
483 \$42 thousand for other challenge grants in the base period.

484 **Q. Does the Company agree to incorporate the adjustments as proposed by Ms.**
485 **Ramas and Ms. Salter?**

486 A. Yes. The Company has included an adjustment to remove the rent contribution
487 and challenge grants from the filing as shown on page 12.11 of Exhibit
488 RMP__(SRM-2R). This reduces the Company's revenue requirement by
489 approximately \$208,000.

490 **Incremental Bonus Depreciation Update**

491 **Q. Please explain the concept of bonus depreciation as it relates to this case.**

492 A. Bonus depreciation refers to a first-year tax depreciation allowance for qualified
493 property. The adjusted basis of the property is reduced by the bonus depreciation
494 before computing the amount otherwise allowable as a tax depreciation deduction
495 for the tax year and any later tax year. Pursuant to the Tax Relief, Unemployment
496 Insurance Reauthorization, Job Creation Act ("the Act"), which was signed into
497 law on December 17, 2010, 50 percent bonus depreciation was extended through
498 2012 on qualifying property, and qualified property acquired and placed in service
499 after September 8, 2010, and before January 1, 2012, became eligible for 100
500 percent first-year bonus depreciation. Bonus depreciation does not impact the
501 total level of income tax expense in the test year, but it does give rise to additional
502 accumulated deferred income taxes which are included as a reduction to rate base.

503 The Company's direct filing in this case reflected the Company's
504 interpretation of the Act just after it was signed into law. Based on this

505 preliminary analysis of the Act, the vast majority of property included in this case
506 placed into service after September 8, 2010, and before January 1, 2012, was
507 assumed to be eligible for 100 percent first-year bonus depreciation. Property
508 forecast to be placed into service between January 1, 2012, and June 30, 2012,
509 was assumed to be eligible for 50 percent first-year bonus depreciation.

510 **Q. If the impact of bonus depreciation was already included in the Company's**
511 **filing why is an additional adjustment required now?**

512 A. OCS witness Ms. Ramas and DPU witness Mr. Matthew Croft both correctly
513 point out that an adjustment is required to correct the impact of bonus
514 depreciation due to guidance received from the Internal Revenue Service ("IRS")
515 regarding the applicability of the Act to assets included in this case.

516 **Q. Will you further explain the IRS guidance and how it would change the**
517 **Company's filing?**

518 A. Yes. On March 29, 2011, the IRS issued guidance in Revenue Procedure 2011-26,
519 which clarified that under the Act, self-constructed property is acquired when
520 manufacture, construction, or production of the property begins. This date may be
521 determined by identifying when physical work of a significant nature begins
522 under a facts-and-circumstances analysis or under a 10 percent safe harbor. Post
523 rate case filing and utilization of this guidance requires that the acquisition date of
524 certain self-constructed property, such as the Populus to Ben Lomond
525 transmission line, which was placed in service in November 2010, be considered
526 as having occurred prior to September 8, 2010. Accordingly this project only
527 qualifies for 50 percent bonus depreciation not 100 percent bonus depreciation as

528 assumed in the Company's original filing.

529 Accordingly, the Company has recomputed the impact of the Act in this
530 case consistent with the IRS guidance. I have provided the necessary adjustment
531 and corrected the revenue requirement. The Company provided this adjustment in
532 its response to OCS data request 27.2 on May 18, 2011, to provide parties the
533 opportunity to review the impact of the IRS guidance. Revenue requirement in
534 this case is increased by approximately \$9.3 million when bonus depreciation is
535 properly reflected.

536 **Q. Ms. Ramas also makes reference to an application filed by the OCS (Docket**
537 **No. 11-035-47) requesting deferred accounting treatment of bonus**
538 **depreciation as it relates to previous Utah dockets. Does your rebuttal**
539 **adjustment address that application or any previous Utah dockets?**

540 A. No. The adjustment made in the Company's rebuttal filing is specific to this case
541 and does not address the application filed by the OCS. The implications of the
542 Act on previous cases will be considered in Docket No. 11-035-47.

543 **Pro Forma Plant Additions and Retirements**

544 **Q. Various witnesses for intervening parties have proposed adjustments to**
545 **capital additions. Does the Company agree with these proposed adjustments?**

546 A. Mr. Croft of the DPU, Ms. Ramas of the OCS, and Mr. Jim T. Selecky of UIEC
547 have all proposed adjustments to the Company's capital additions. The Company
548 is accepting in principle adjustments to capital additions, plant retirements,
549 depreciation expense, and depreciation reserve which result from using actual
550 capital additions and retirements for July 2010 to March 2011 and updating April

551 2011 to June 2012 capital additions as proposed by DPU witness Mr. Croft. The
552 Company is not adopting Mr. Croft's adjustment to update composite
553 depreciation rates and recalculate retirement rates included in the filing. The
554 Company is accepting Ms. Ramas' adjustment to replace July 2010 to March
555 2011 forecast capital and retirements with actuals for that same time period, but
556 rejecting Ms. Ramas' adjustment to reduce April 2011 to June 2012 forecasted
557 capital additions by 4.34 percent. The Company is also rejecting Mr. Selecky's
558 adjustment to remove capital additions with an in-service date after September 21,
559 2011. The proposed adjustments listed above that are adopted by the Company
560 are discussed in this section. The proposed adjustments listed above that the
561 Company is rejecting are discussed in the Adjustments Disputed by the Company
562 section below.

563 **Q. Please explain the Company's adjustments to proforma plant additions and**
564 **retirements, depreciation and amortization expense, and depreciation and**
565 **amortization reserve.**

566 A. The Company's rebuttal adjustment to capital additions and plant retirements is
567 calculated using actual additions and retirements from July 2010 to March 2011,
568 including the change in the balance in FERC account 106 (unclassified plant).
569 Adjustment 12.13 (Pro Forma Plant Additions and Retirements) in Exhibit
570 RMP__(SRM-2R) also includes updates to the forecast amounts and project in-
571 service dates for the projected April 2011 through June 2012 time period, as
572 provided in the Company's response to Data Request DPU 30.3. In that response
573 the Company provided information regarding projects that were placed into

574 service early or late, that have been delayed past June 2012, or that were not
575 included in the original filing.

576 Adjustment 12.13 also includes additional amounts to be placed into
577 service for the Transmission Clearance project beyond what was included in the
578 filing; \$6.2 million in 2011 and \$22.3 million in January 2012 through June 2012.
579 These projects were implemented to comply with both 1) The National Electric
580 Safety Code (“NESC”) clearance requirements; and 2) a North American Electric
581 Reliability Corporation (“NERC”) Alert released in late 2010. Recent surveys of
582 select lines have identified several spans which, if loaded to published capacity,
583 would violate the allowable NESC clearance. The first phase of clearance
584 correction projects is to correct these potential issues. In late 2010 NERC issued a
585 reliability alert requiring utilities to verify that published line ratings met field
586 conditions. Per the NERC alert, phase two of the clearance correction projects
587 will implement additional line surveys and make corrections where necessary.
588 The NERC alert requires a three year assessment and a three year remediation,
589 with remediation being a year behind assessment. Of the increase in 2011, \$3.2
590 million is due to the first phase and is a combination of additional issues added to
591 the project as well as increased costs. The remaining \$3 million increase in 2011
592 and the \$22.3 million increase in January 2012 through June 2012 are due to
593 phase two of this project.

594 Adjustment 12.13 also includes the retirements related to the sale of
595 transmission assets to Black Hills Power Corporation, the sale of the Snake Creek
596 hydroelectric plant to Heber Light & Power, and the removal of the Condit

597 hydroelectric project, which will be discussed later in my testimony in the
598 Miscellaneous Asset Removal section.

599 Adjustment 12.16 revises depreciation expense consistent with the
600 changes made to plant in service amounts. Adjustment 12.17 reflects the changes
601 to the depreciation reserve based on changes in depreciation expense, plant
602 additions and plant retirements. Adjustment 12.18 updates deferred taxes based on
603 changes to plant in service amounts.

604 **Miscellaneous Asset Removals**

605 **Q. Please provide an overview of your proposed adjustment entitled**
606 **Miscellaneous Asset Removals.**

607 A. This adjusts the Company's filing for the impacts related to the sale of
608 transmission assets to Black Hills Power Corporation ("BHP"), the sale of the
609 Snake Creek hydroelectric plant to Heber Light & Power ("Heber Power"), and
610 the removal of the Condit hydroelectric project ("Condit Project"). I will discuss
611 each project separately.

612 **Q. Please give a brief description of the sale of transmission plant to BHP.**

613 A. On December 29, 2010, the Company sold ownership interests in certain
614 transmission assets to BHP. Some of the underlying assets sold were existing
615 plant that was in service and some of the assets were planned capital additions and
616 upgrades to existing assets. The Company's original filing properly reflected the
617 future capital additions associated with the transaction at only the amount related
618 to the Company's ownership interest. However, the plant balances and associated
619 expense for the existing assets sold were not excluded in the Company's original

620 request.

621 **Q. Please describe Dr. Jodi Zenger’s and Mr. Higgins’ recommendations**
622 **regarding the Company’s sale of transmission plant to BHP.**

623 A. Dr. Zenger and Mr. Higgins recommend that the Company’s filing be updated to
624 reflect the sale of these assets as they are no longer used to serve customers. At
625 the time of filing their direct testimonies, both the DPU and UAE had pending
626 data requests asking for the actual amounts included in the filing related to the
627 sale. Thus, both Dr. Zenger and Mr. Higgins include placeholders in their
628 testimonies for the sale. Dr. Zenger uses estimated amounts from filings in
629 Oregon, Wyoming and the Federal Energy Regulatory Commission (“FERC”),
630 stating an update to the actual figures will be necessary. Mr. Higgins’ direct
631 testimony does not include an actual adjustment; however, he discloses his intent
632 to supplement his testimony once the data is received.

633 **Q. Does the Company agree that an adjustment should be made to reflect the**
634 **sale of these assets to BHP?**

635 A. Yes. The Company agrees that the filing should fully reflect the impacts of the
636 sale of transmission assets to BHP. In total, this adjustment reduces Utah
637 allocated rate base by approximately \$1.6 million and expense by approximately
638 \$88 thousand.

639 **Q. On page 6, line 115-116 of Dr. Zenger’s testimony, she gives an estimated**
640 **price for the sale and an estimated gain on the sale. Does she cite how she**
641 **arrived at these numbers?**

642 A. Yes she does. As stated by Dr. Zenger, those numbers came from an advice filing

643 the Company made with the Oregon Public Utility Commission in October 2010
644 asking for permission to complete the transaction with BHP, which contained
645 preliminary estimates on the details of the transaction. The Company
646 subsequently filed a compliance filing with the Oregon PUC on January 28, 2011
647 updating the original estimates to the actual numbers related to the sale to BHP.

648 **Q. Is there any other information regarding the BHP agreement that you would**
649 **like to add?**

650 A. Yes. The Company and BHP executed a Purchase and Sale Agreement on
651 February 18, 2010. The terms of the agreement state that BHP will be responsible
652 for the costs of their share of these projects. Since the agreement stipulates that
653 the final purchase price will be adjusted at closing for actual costs and expenses
654 related to the additions and upgrades, Utah ratepayers will not bear the
655 responsibility for the costs of the upgrades to the assets sold that are not being
656 used to serve them.

657 **Q. Please give a brief description of the sale of Snake Creek hydroelectric plant**
658 **to Heber Power.**

659 A. The Company is in the process of selling its Snake Creek hydroelectric generation
660 plant facilities located in Wasatch County, Utah to Heber Power. This transaction
661 is anticipated to close on September 1, 2011.

662 **Q. What is Mr. Higgins' recommendation regarding this sale?**

663 A. Mr. Higgins recommends that the Company's request be updated to reflect the
664 sale of these assets. Mr. Higgins' direct testimony does not include an actual
665 adjustment, but he states his intent to update his direct testimony once he receives

666 the necessary data in a pending data request.

667 **Q. Does the Company agree with Mr. Higgins' proposal that an adjustment**
668 **should be made to the Company's request to reflect the sale of these assets to**
669 **Heber Power?**

670 A. Yes. The Company agrees that the filing should fully reflect the impacts of the
671 sale of the Snake Creek hydroelectric plant to Heber Power. Please see
672 Confidential Exhibit RMP__(SRM-4R) for the adjustment details related to Snake
673 Creek.

674 **Q. Did the Company realize a gain on any of the miscellaneous asset sales?**

675 A. [REDACTED]
676 [REDACTED]
677 [REDACTED]
678 [REDACTED]
679 [REDACTED]
680 [REDACTED]
681 [REDACTED]
682 [REDACTED]
683 [REDACTED]
684 [REDACTED]
685 [REDACTED]
686 [REDACTED]

687 **Q. Please give a brief description of the removal of the Condit Project.**

688 A. The Condit Project is located in south-central Washington on the White Salmon

689 River. The Company is moving forward with the decommissioning of the facility
690 after receipt of an essential sediment management permit from the U.S. Army
691 Corps of Engineers (“Corps”), the final major regulatory step. The
692 decommissioning and removal of this facility results from a relicensing process
693 that began in 1991 and culminated in a multi-party settlement agreement in 1999.
694 On Dec. 16, 2010, the Company received a Surrender Order from FERC
695 providing for dam decommissioning. FERC modified the Surrender Order on
696 April 21, 2011, which, along with the Corps permit, provides the regulatory
697 certainty the Company needed to proceed to remove the dam. On June 8, 2011,
698 FERC completed its review and approval of requisite project removal design and
699 resource management plans. Dam removal was determined to be less costly to
700 customers than the fish passage that would be required for operation as part of the
701 federal dam relicensing process. After the initial breach and draining of the
702 reservoir in November 2011, demolition of the remaining portion of the dam is
703 scheduled to begin in the spring of 2012 and be completed by August 31, 2012.
704 Restoration work throughout the former reservoir area is planned to be completed
705 by the end of 2012.

706 **Q. Have any adjustments been proposed related to the removal of the Condit**
707 **Project in this case?**

708 A. No. During the time of preparing the original filing and the time the intervening
709 parties were preparing their direct testimonies, the Company was in the process of
710 seeking the necessary regulatory approvals to remove the dam. As detailed
711 above, the Company received the necessary regulatory approvals during rebuttal

712 preparation. Therefore, the Company proposes to update the case to reflect the
713 impact of removing the Condit Project. In total, this adjustment reduces Utah
714 allocated rate base by approximately \$38 thousand and expense by approximately
715 \$323 thousand. The impact of removing the Condit Project is also reflected in the
716 Company's updated net power costs.

717 **Q. How did you incorporate into revenue requirement the adjustments for the**
718 **sale of transmission assets to BHP, the sale of the Snake Creek hydroelectric**
719 **plant to Heber Power, and the removal of the Condit Project?**

720 A. The electric plant in service and the accumulated depreciation balances for each
721 asset sold or removed are adjusted in the Pro Forma Plant Additions and
722 Retirements adjustment on page 12.13 and the Depreciation Reserve Update on
723 page 12.17, respectively. Depreciation expense is adjusted for the assets sold or
724 removed in the Depreciation Expense Update adjustment on page 12.16. The
725 accumulated deferred income tax balance impacts are included in the Plant
726 Related Tax Update on page 12.18. The O&M expense and gains associated with
727 the transactions are included in the Miscellaneous Asset Removal adjustment on
728 page 12.14. Confidential exhibit RMP__(SRM-4R) provides the details of each
729 asset sold or removed, summarizing the impacts by FERC account and
730 jurisdictional allocation factor. Finally, the net power cost impacts associated
731 with the Condit Project removal are reflected in the Net Power Costs adjustment
732 on page 12.22.

733 **Bridger and Trapper Mines**

734 **Q. Please explain the adjustment to the Trapper and Bridger mine rate base.**

735 A. DPU witness Mr. Croft proposed a modest increase to the Trapper and Bridger
736 rate base amounts. The adjustment increases the Trapper rate base by
737 approximately \$307 thousand, the Trapper reclamation liability by approximately
738 \$5 thousand, and the Bridger rate base by approximately \$441 thousand, resulting
739 in a net rate base increase of \$752 thousand on a total company basis, or \$320
740 thousand Utah-allocated. The ratemaking impact of this adjustment increases
741 revenue requirement by approximately \$37 thousand. The Company has accepted
742 this adjustment, which is included as Adjustment 12.15 in Exhibit RMP__(SRM-
743 2R).

744 **Q. What is the basis for Mr. Croft's adjustment?**

745 A. At the time of the Company's original filing, the Test Period rate base amounts
746 for the Trapper and Bridger mines were based on actual results for the period June
747 2009 through September 2010 and forecast results from October 2010 through
748 June 2012. During the discovery phase of this proceeding, the DPU submitted
749 data requests asking the Company provide actual monthly updates as they became
750 available. At the time the DPU filed its direct testimony, the Company had
751 provided actual balances for the months of October 2010 through February 2011.
752 Mr. Croft used these updated actual balances to impute forecast amounts for the
753 Test Period.

754 **Q. How did Mr. Croft impute the forecast amounts for the Test Period?**

755 A. He replaced the forecast monthly balances for the months October 2010 through

756 February 2011 with the actual amounts. He then revised the each of the monthly
757 forecast balances for the period March 2011 through June 2012 by the
758 incremental monthly difference included in the Company's original filing.

759 **Deferred Income Tax Allocation Correction**

760 **Q. Please explain the adjustment to correct the allocation of deferred income**
761 **taxes.**

762 A. Adjustment 12.19 in Exhibit RMP__(SRM-2R) corrects the allocation factor
763 assigned to various deferred tax items that were incorporated in the original filing.
764 This issue was noted in Company responses to OCS data request 14.1 and DPU
765 data request 7.58, and DPU witness Mr. Croft and OCS witness Ms. Ramas both
766 proposed adjustments to reflect these corrections. The total impact of the
767 correction on revenue requirement was a reduction of approximately \$112
768 thousand.

769 **Cottonwood Coal Lease**

770 **Q. Please provide a brief description of the Company's Cottonwood Coal Lease**
771 **Adjustment?**

772 A. The Company has incorporated the purchase of the Cottonwood coal lease into
773 plant held for future use in Adjustment 12.20 in Exhibit RMP__(SRM-2R). The
774 payments for this coal lease will be made in June 2011 and January 2012.
775 Company witness Ms. Cindy Crane provides more details regarding why it should
776 be included in the Test Period.

777 **Powerdale Decommissioning**

778 **Q. Please describe the adjustment Ms. Ramas recommends regarding the**
779 **Powerdale hydroelectric plant decommissioning project.**

780 A. Docket No. 07-035-93 included an estimated amount of approximately \$5.9
781 million for the cost to decommission the Powerdale hydroelectric plant. The
782 majority of the decommissioning project was completed by the end of 2010 and
783 the actual costs were approximately \$4.2 million. Therefore, Ms. Ramas
784 concludes the Company has over-recovered costs associated with Powerdale
785 decommissioning project and recommends the difference between the estimate
786 used in Docket No. 07-035-93 and the amount actually spent of be returned to
787 customers over two years. The Utah-allocated impact of her adjustment reduces
788 revenue requirement by approximately \$370 thousand.

789 **Q. Please discuss the Company's response to her proposal.**

790 A. Ratemaking treatment for Powerdale decommissioning costs was unique in that it
791 relied on a forecast of costs prepared several years in advance of the funds
792 actually being spent and related to a project that would span several years.

793 **Q. Does the Company accept Ms. Ramas' adjustment?**

794 A. Yes. The Company accepts Ms. Ramas' proposal for a true-up of the forecast
795 used in Docket No. 07-035-93 to the actual costs incurred for Powerdale
796 decommissioning. This adjustment is included on page 12.21 of Exhibit
797 RMP__(SRM-2R).

798 **Net Power Costs**

799 **Q. Have you incorporated any changes to net power costs in the rebuttal**
800 **revenue requirement?**

801 A. Yes. Company witness Mr. Gregory N. Duvall provides rebuttal testimony
802 related to net power costs and supports specific adjustments to Test Period net
803 power costs in this case. I have incorporated adjustments supported by Mr.
804 Duvall into the rebuttal revenue requirement. Overall, these adjustments reduce
805 Utah allocated revenue requirement by approximately \$5.3 million.

806 **Adjustments Disputed by the Company**

807 **Line Losses**

808 **Q. Did you alter the jurisdictional allocation factors to incorporate Ms. Ramas’**
809 **recommendation to line losses?**

810 A. No. The Company does not agree with Ms. Ramas’ adjustment to the Company’s
811 line losses. A full discussion on the Company’s position is included in the
812 rebuttal testimony of Mr. Duvall.

813 **Ancillary Revenue**

814 **Q. Please describe the adjustment proposed by Mr. Higgins with regards to the**
815 **contract for ancillary services with Seattle City Light.**

816 A. The Company currently has a contract to provide ancillary services to Seattle City
817 Light that expires on December 31, 2011. Since the contract expires midway
818 through the Test Period the Company removed half of the revenue associated with
819 the contract in its original filing. Mr. Higgins adds that revenue back to the
820 Company’s case.

821 The Company does not agree that leaving revenue in for the entire Test
822 Period is appropriate since the terms and conditions of a new agreement with
823 Seattle City Light, if any, are not known. The Company is currently in
824 negotiations with Seattle City Light on a possible long-term contract to replace
825 the contract that is expiring, and if a new contract is timely finalized it will be
826 included in the Company's surrebuttal filing.

827 **Non-T&D Insurance**

828 **Q. Please describe the adjustment proposed by Ms. Ramas regarding non-T&D**
829 **insurance.**

830 A. Ms. Ramas proposes removing the Swift hydro facility flood damage from the
831 basis for reserve accrual. According to Ms. Ramas, the January 2009 event at the
832 Swift facility was a "unique event that would not occur in a typical year."

833 **Q. Do you feel the Swift flood was an unusual one-time event to be excluded in**
834 **determining the average cost level to include in base rates?**

835 A. No. Although this identical event is unlikely to occur at the Swift hydro plant
836 again, it is likely that other damages will occur somewhere in the Company's
837 system. The purpose of insurance is to protect against unusual events; each event
838 that is covered by the reserve accrual could be categorized as unusual and non-
839 recurring. But over time, while catastrophic events such as the one at the Swift
840 plant will happen, overall frequency of such events have a measure of continuity
841 and therefore it is a prudent business practice to recover a small amount from
842 customers each year to help levelize these costs.

843 **Q. Could rejecting Ms. Ramas adjustment cause long-term harm to customers?**

844 A. No. As described in my direct testimony on page 26, the Company will be self
845 insured in separate accounts for each jurisdiction. These accounts will be used to
846 record actual damages above the deductible described in my testimony. Any
847 unused reserve balances results in a rate base reduction that will be carried
848 forward into future periods. The question raised in Ms. Ramas' testimony appears
849 to not be whether these costs should be recovered from customers, but whether we
850 should accumulate a balance now, or wait until after a major event occurs. It is
851 the Company's opinion that customers would be better served by accruing a
852 reserve from customers to be used when an event occurs. If the reserve balance
853 goes unused for a period of time, future accruals could be adjusted in a
854 subsequent rate case.

855 **Uncollectible Expense**

856 **Q. Please summarize the adjustments proposed to the Company's uncollectible**
857 **expense.**

858 A. DPU witness Ms. Salter proposes to adjust the Company's uncollectible expense
859 to a five-year rolling average. OCS Witness Ms. Ramas recommends that the
860 Company's uncollectible expense be adjusted to the Company's target rate of 0.27
861 percent. The proposed adjustments reduce the Company's Utah-allocated
862 uncollectible expense by approximately \$367 thousand and \$760 thousand,
863 respectively.

864 **Q. How did the Company treat uncollectible expense in its original filing.**

865 A. The Company determined the Test Period uncollectible expense by first

866 calculating the unadjusted uncollectible rate (Utah’s FERC 904 expense divided
 867 by Utah’s general business revenues) and then applying that rate to the Test
 868 Period general business revenues. When considering the methodology to use in
 869 this case, the Company analyzed the actual June 2010 uncollectible expense to
 870 determine the reasonableness of the amount. The Company concluded that the
 871 unadjusted June 2010 uncollectible rate was less than the comparable three year
 872 average method used in the previous rate case and represented a reasonable level
 873 of expense that can be expected during the Test Period.

874 In Docket No. 09-035-23, the Commission accepted Ms. Salter’s
 875 recommendation to adjust the Test Period uncollectible expense to a three-year
 876 historical average. In this case, the Company discovered that applying that
 877 methodology produced an increase to the Company’s uncollectible expense.
 878 Since the June 2010 level of uncollectible expense seemed to be reasonable, the
 879 Company only adjusted the uncollectible expense to account for the additional
 880 revenue that will arise as a result of this case. The analysis is highlighted in the
 881 table below.

<i>Utah Uncollectible Expense</i>			
	Jun-08	Jun-09	Jun-10
Utah FERC 904 Expense	\$ 4,396,680	\$ 5,208,240	\$ 4,709,966
Utah General Business Revenue	\$ 1,412,248,643	\$ 1,420,886,725	\$ 1,496,868,201
Uncollectible Rate	0.311%	0.367%	0.315%
		As filed	0.315%
		3 Year Average	0.331%

882 **Q. Ms. Salter claims the Company’s method does not take into account the**
 883 **volatility of uncollectible expense. Please address her concern.**

884 A. If Ms. Salter is concerned with volatility, she should have proposed the same

885 adjustment as was done in the last rate case. However, Ms. Salter's adjustment
886 seems to be guided more by trying to get a lower amount than to reduce volatility.
887 The purpose of adjusting uncollectible expense should be to set a reasonable level
888 that will as closely as possible represent the actual expense that will be incurred
889 during the Test Period. As shown in the table above, the base period expense
890 does not seem to be out of line from a historical perspective.

891 **Q. How does Ms. Salter propose to calculate uncollectible expense in this case?**

892 A. Ms. Salter uses a five year rolling average of ten historical uncollectible
893 percentages. Based on this she concludes that a 0.29 percent uncollectible rate is
894 appropriate, which reduces the Company's uncollectible expense by
895 approximately \$367 thousand.

896 **Q. How does her methodology proposed in this case differ from the**
897 **methodology proposed and accepted by the Commission in Docket No. 09-**
898 **035-23?**

899 A. She changed her methodology from a three year historical average to a five year
900 rolling average that uses ten overlapping data points.

901 **Q. Does Ms. Salter provide sufficient evidence to support her change in**
902 **methodology?**

903 A. No. She claims a three year average would not properly reflect the recession,
904 which she deems an "anomalous period." Ms. Salter employed this same
905 argument in the last case, and her predictions that the economy would recover
906 during the test period did not materialize. Her argument fails to consider the fact
907 that Utah's economy continues to experience hardships that are not expected to

908 subside for several years. Consequently, the level of uncollectible expense that
909 has been seen in 2008 and 2009 is more likely to reflect the economic conditions
910 that will be present during the time the rates are in effect than the robust economic
911 periods prior to the recession. It is concerning that Ms. Salter's methodology
912 seems to have changed only because the three year average methodology that she
913 recommended in the last case did not produce the same result in this case. Her
914 proposal effectively denies the Company the ability to fully recover its
915 uncollectible expense, which is an unavoidable cost of serving customers. In
916 Docket No. 09-035-23, the Company requested the Commission set a policy in
917 anticipation of this issue. The Company again respectfully requests the
918 Commission set a consistent approach to calculating uncollectible expense, and
919 not base the rate on proposed adjustments designed to come up with the lowest
920 possible forecast for each individual case.

921 **Q. Please describe the adjustment made by Ms. Ramas to the Company's**
922 **uncollectible expense.**

923 A. Ms. Ramas proposes to adjust the Company's uncollectible expense to the
924 Company's target rate of 0.27 percent. Her adjustment reduces Utah's
925 uncollectible expense by approximately \$760 thousand.

926 **Q. Historically has the Commission recognized the use of the Company's target**
927 **rate as an acceptable methodology for calculating uncollectible expense?**

928 A. No. Past Commission practice has generally not favored the use of the
929 Company's target uncollectible rate for determining uncollectible expense. In my
930 rebuttal testimony in Docket No. 09-035-93, I proposed to use the Company's

931 0.27 percent target uncollectible rate to set the Test Period level of uncollectible
932 expense as an alternative to Ms. Salter’s three year historical average adjustment.
933 In the order in that case, the Commission rejected the Company’s proposal to use
934 the target rate stating, “Our general approach to normalize abnormal amounts is to
935 use an average. In this case, therefore, we prefer the Division’s use of an
936 historical average over a management forecast.”

937 **Glenrock Coal Mine**

938 **Q. Do you agree with the adjustment proposed by DPU witness Ms. Salter to**
939 **remove amortization related to the Glenrock coal mine closure?**

940 A. No. The Company included an adjustment in its initial filing to remove the
941 amortization of the Glenrock coal mine closure from Test Period results.
942 Adjustment 8.11 in Exhibit RMP__(SRM-3) removes \$454,856 from operating
943 results, representing \$437,818 of amortization in the base period, escalated by
944 3.89 percent for the Test Period. While Ms. Salter correctly points out that the
945 regulatory asset for Glenrock mine closure costs was fully amortized in
946 September 2010, her adjustment would remove costs that are already excluded
947 from the case.

948 **O&M Expense Escalation**

949 **Q. Please explain the adjustment to the escalation of non-labor O&M costs**
950 **proposed by Mr. Higgins.**

951 A. Mr. Higgins’ proposed adjustment removes the increases in non-labor O&M
952 expense as projected by IHS Global Insight (USA) Inc. (“IHS”) from the base
953 period through the Test Period. He cites two primary concerns: 1) including a

954 provision for escalation in rates makes inflation a “self-fulfilled prophecy”; and 2)
955 including escalation in the Company’s rates builds a “cost cushion” and provides
956 a disincentive for the Company to improve efficiency.

957 **Q. Do you agree with his concerns?**

958 A. No. Mr. Higgins’ argument that including a forecast of inflation in the
959 Company’s case becomes a self-fulfilling prophecy is overreaching. His proposed
960 adjustment is based solely on his interpretation of high-level economic indicators
961 and not empirical evidence of the cost pressures facing the utility industry. The
962 Company is simply reflecting the cost of goods and services that it will
963 experience during the Test Period. If these cost increases are not reflected in the
964 Company’s projected revenue requirement it will impact the Company’s ability to
965 recover the cost it will necessarily incur to serve customers during the rate-
966 effective period.

967 **Q. Do you agree that including escalation serves as a “cost cushion” for the**
968 **Company?**

969 A. No. Planning for the costs the Company will incur in serving customers during the
970 Test Period is not a cost cushion, but a prudent and accepted practice in setting
971 rates that will allow the Company an opportunity to recover its prudently incurred
972 cost of providing safe and reliable electrical service. Adopting Mr. Higgins’
973 adjustment that holds the Company’s non-labor O&M flat would only result in
974 chronic under recovery of costs.

975 **Q. What additional arguments does Mr. Higgins provide to support his**
976 **adjustment?**

977 A. Mr. Higgins claims that inflationary pressures will not be substantial during the
978 Company's Test Period. The source for his claim is the Minutes of the Federal
979 Reserve Open Market Committee for April 26-27, 2011. This document contains
980 high level discussion of national economic factors including core inflation, which
981 is anticipated to be in the range of 1.3 percent to 1.6 percent in 2011 and 1.3
982 percent to 1.8 percent for 2012.

983 **Q. Why does the Company believe that the IHS escalation factors included in**
984 **the case are more appropriate than Mr. Higgins' core inflation argument?**

985 A. IHS conducts research that is specialized to the electric utility industry. Based on
986 its research, IHS formulates escalation factors related to specific FERC accounts.
987 In contrast, Mr. Higgins' argument is based on core inflation, which is a broad
988 predictor of inflation that is measured based on aggregate price growth excluding
989 food and energy prices. While core inflation can be a valuable tool when
990 examining the economy as a whole, it is too broad to be an accurate predictor of
991 the specific cost pressures the Company will experience during the Test Period.

992 **Q. Do you have updated inflation expectations for the Test Period?**

993 A. Yes. IHS releases its Global Insight escalation factors on a quarterly basis. The
994 Company's initial revenue requirement calculation used the third quarter 2010
995 indices (released October 2010), which were the most recent indices available at
996 the time of preparation. Global Insight has since released their fourth quarter 2010
997 indices (released January 2011) and first quarter 2011 indices (released April

998 2011).

999 **Q. Does the updated data from IHS align with Mr. Higgins' assertion that**
1000 **inflationary expectations are low?**

1001 A. No. Based on current analysis of the electrical utility industry, the expectations for
1002 inflation are steadily increasing. Confidential Exhibit RMP____(SRM-3R)
1003 compares the escalation factors used in the Company's request to the two more
1004 recent releases showing inflation between the base period and Test Period in this
1005 case. If the Company were to update the calculation of its requested price
1006 increase using the new releases it would increase the O&M escalation adjustment
1007 by approximately \$273 thousand using the Q4 2010 release and by \$3.6 million
1008 using the Q1 2011 release on a Utah-allocated basis.

1009 **Q. Is the Company requesting to update its request for the new escalation**
1010 **factors?**

1011 A. No. Confidential Exhibit RMP____(SRM-3R) is provided to support the
1012 Company's assertion that its request is reasonable and conservative considering
1013 the fact that an independent research company such as IHS believes cost pressures
1014 in the electrical utility industry are increasing.

1015 **Q. Can the Company provide other evidence demonstrating an upward trend in**
1016 **expectations for inflation?**

1017 A. Yes. Mr. Higgins' source for core inflation actually supports the Company's
1018 assertion that expectations for inflation have steadily increased. Although the
1019 Company does not believe that core inflation is the best measure of inflationary
1020 pressures the Company will be faced with, comparing the Minutes of the Federal

1021 Reserve Open Market Committee from June 2010, November 2010, January
1022 2011, April 2011, and June 2011 reveals an interesting trend in the expectations
1023 of the Federal Reserve Governor and the Reserve Bank Presidents. The following
1024 table provides a comparison of the core inflation projections from Table 1
1025 contained within the minutes released by the Federal Reserve:

Economic Projections of the Federal Reserve Governor & Reserve Bank Presidents		
<i>Release Date</i>	Core Inflation Range	
	<i>CY 2011</i>	<i>CY 2012</i>
June 22-23, 2010	0.8 to 1.0	0.9 to 1.3
November 2-3 2010	1.0 to 1.1	0.9 to 1.6
January 25-26, 2011	1.0 to 1.3	1.0 to 1.5
April 26-27, 2011	1.3 to 1.6	1.3 to 1.8
June 22, 2011	1.5 to 1.8	1.4 to 2.0

1026 The O&M escalation adjustment based on IHS indices included in the
1027 original filing amounts to an increase that is less than two percent annually, an
1028 amount that is supported by the table above.

1029 **Q. Please describe the Commission’s treatment of this issue in past general rate**
1030 **cases.**

1031 A. In Docket No. 07-035-93 the Commission examined this issue and determined
1032 that the Company’s use of Global Insight indices was “appropriate and provide
1033 the Company adequate incentive to manage their non-labor O&M costs (other
1034 than net power costs).” This is also the treatment that was used by the Company
1035 in Docket Nos. 08-035-38 and 09-035-23.

1036 **Q. Please describe the adjustment Mr. Garrett makes to the Company’s O&M**
1037 **escalation adjustment.**

1038 A. Mr. Garret proposes to include an efficiency adjustment savings of 0.5 percent

1039 per year as an offset to the Company's O&M escalation adjustment. He claims
1040 this acts as an incentive for the Company to control its costs.

1041 **Q. Do you find Mr. Garrett's proposal to be reasonable in this general rate**
1042 **case?**

1043 A. No. Mr. Garrett's approach to O&M escalation does not afford the Company the
1044 opportunity to recover the costs it will likely incur to serve customers during the
1045 rate effective period in this case.

1046 **Q. Is an efficiency adjustment necessary in this case?**

1047 A. No. As discussed earlier, Confidential Exhibit RMP____(SRM-3R) shows that
1048 updating to the latest release would increase the Company's revenue requirement
1049 by approximately \$3.6 million Utah-allocated. Based on this, it is evident that the
1050 level of non-labor, non-NPC O&M expense included in the case as escalated will
1051 likely be substantially lower than the cost increases the Company will actually
1052 face during the Test Period. Thus, the Company will need to find efficiencies just
1053 to be able operate within the amount included in the original request. Mr.
1054 Garrett's efficiency adjustment is not necessary and will only penalize the
1055 Company for costs outside its control.

1056 **Q. Can you provide an example of such a cost?**

1057 A. Yes. In June 2011, the Company was notified that its Utah Public Utilities
1058 Regulation fee for fiscal year 2012 had increased by over \$1.2 million, or 38
1059 percent, as compared to the fee assessed for fiscal year 2011. The fee is
1060 calculated by multiplying the amount of operating revenues for the preceding
1061 calendar year by an assessment rate. While part of the year over year increase

1062 resulted from increased operating revenues, the majority of the increase was due
1063 to the fact that the assessment rate was increased by over 27 percent more than the
1064 previous year. This is just one example of an increased operating expense that is
1065 outside of the Company's control that will have to be absorbed by other operating
1066 efficiencies.

1067 **Q. What evidence does Mr. Garrett provide to support his calculation that an**
1068 **appropriate level for an efficiency adjustment is 0.5 percent?**

1069 A. Mr. Garrett supports this number by stating that the Company has used a similar
1070 productivity offset in its post-test year attrition ratemaking adjustment filings in
1071 its California jurisdiction. Therefore, he claims the same type of adjustment is
1072 warranted in Utah when a forecasted test year is used.

1073 **Q. Do you agree with this argument?**

1074 A. No. The regulatory environment in which the Company operates in the state of
1075 California is vastly different than in Utah. The California Commission requires
1076 the Company to file general rate cases every three years in California. Between
1077 rate cases, a variety of mechanisms are approved for use by the Company in
1078 California as a way to recover prudently incurred costs. One of such mechanisms
1079 is the one referred to by Mr. Garrett called the Post-Test Year Ratemaking
1080 Adjustment ("PTAM") mechanism. The PTAM Attrition is a mechanism which
1081 enables the Company to timely recover prudently incurred cost increases without
1082 filing a general rate case. PTAM Attrition filings are specific mechanisms for use
1083 by the Company in California that do not examine every individual revenue
1084 requirement component and cannot be compared to a general rate case in Utah.

1085 **Q. Can the Company provide any examples of other jurisdictions where the**
1086 **Company’s requested O&M escalation methodology is utilized?**

1087 A. Yes. Oregon and Wyoming utilize forecast test periods, and the Company makes
1088 an O&M escalation adjustment in its rate cases in those states. No productivity
1089 offset is required in those states.

1090 **Cash Working Capital**

1091 **Q. Are you familiar with the adjustment to the lead lag study being proposed by**
1092 **DPU witness Mr. Garrett?**

1093 A. Yes. Mr. Garrett addresses the cash working capital issue raised in Docket No.
1094 07-035-93. In its final Order, the Commission did not adopt the recommendation
1095 to include long-term debt interest expense in the lead lag study, but reaffirmed its
1096 earlier decision in Docket No. 93-057-01. However, the Commission stated it
1097 would be open to addressing the issue in the next general rate case but noted “[i]f
1098 this method is to be changed, a strong burden of persuasion will first have to be
1099 met which must include a comprehensive analysis of all four of the above
1100 mentioned items.” Mr. Garrett briefly addresses the four specific items outlined
1101 by the Commission in Docket No. 93-057-01, which are (1) depreciation, (2)
1102 interest expense, (3) preferred dividends, and (4) common dividends and how
1103 these pertain to the calculation of working capital, but Mr. Garrett did not include
1104 a comprehensive analysis of the four items.

1105 **Q. Why is it important to include a comprehensive analysis of all four of these**
1106 **items?**

1107 A. Together, these four items constitute what is known as “return on” and “return of”

1108 capital. Because these four items are integrally related, it is important to look at
1109 all of them together, not in the piecemeal manner done by Mr. Garrett.

1110 **Q. Did the Company prepare the December 2007 lead lag study consistent with**
1111 **the Commission’s current cash working capital policy (“CWC”)?**

1112 A. Yes. Consistent with the Commission’s CWC policy,⁴ the Company excluded
1113 depreciation expense, long-term debt interest expense, and dividends on both
1114 preferred and common stock from its December 2007 lead lag study. These four
1115 components have never been authorized by the Commission for inclusion in the
1116 calculation of cash working capital.

1117 **Q. Do you agree with Mr. Garrett’s recommendation to continue to exclude**
1118 **depreciation and common dividends from the lead lag study?**

1119 A. Yes.

1120 **Q. Do you agree with Mr. Garrett’s recommendation to include long-term debt**
1121 **interest expense and preferred dividends in the lead lag study?**

1122 A. No. Mr. Garrett’s main argument for including interest expense in the CWC
1123 calculation is that it is labeled as a “cash” item. The Company does not refute the
1124 idea that interest expense is a cash item, just like the Company’s capital
1125 investments are cash items. However, neither one should be included in the CWC
1126 calculation. CWC is the amount of capital required for operations only and does
1127 not include amounts for non-operational items such as return on rate base. It
1128 should exclude the capital required to finance assets and non-cash expenses such
1129 as depreciation. Historically, regulators often calculated CWC using the 1/8
1130 method of annual operating expenses. Consequently, CWC calculations were the

⁴ UPSC Docket No. 07-035-93, Order issued August 11, 2008.

1131 direct result of operating activities only. Interest on bonds and preferred stock
1132 dividends are elements of the return component in the revenue requirement
1133 calculation, not part of the operating activities of the Company.

1134 Because bonds, preferred stock, and common equity are used to finance
1135 the fixed assets of the utility, the related costs, including any lag in cash
1136 payments, are incorporated in the return on rate base. Intervenors sometimes
1137 propose to include the lag on long term interest payments in the CWC calculation,
1138 but they often disregard the lag on short term interest payments. Short-term debt
1139 costs are recovered through Allowance for Funds Used During Construction
1140 (“AFUDC”) on Construction Work in Progress (“CWIP”), and ultimately through
1141 depreciation expense over the life of the asset, after CWIP is transferred to rate
1142 base.

1143 The same situation occurs relative to long-term debt cost, which is
1144 recovered through the return component in the revenue requirement. To separate
1145 out only long-term interest expense payment lag, and reduce rate base, will
1146 misstate the overall revenue requirement. Neither short-term nor long-term
1147 interest expense should impact operating capital. The Company’s CWC
1148 calculation appropriately excludes both.

1149 To reiterate what the Company expressed in testimony in Docket No. 07-
1150 035-93, the idea of recognizing a cash “lead” for interest is a well-worn notion
1151 that is given little credence by recognized authorities in the field of utility
1152 accounting. Mr. Robert L. Hahne addresses this issue in his book, Accounting for
1153 Public Utilities, which discusses a number of disfavored adjustments that have

1154 been proposed for determining cash working capital. He places at one extreme
1155 those who would recognize a lag in the receipt of operating income while
1156 ignoring delays in the disbursement of interest. At the other end of the spectrum
1157 he places those (such as Mr. Garrett) who would recognize that working capital
1158 exists in the delay in disbursements of interest without consideration of the lag in
1159 receipt of operating income. Mr. Hahne goes on to say that few Commissions
1160 have accepted either of these points of view. Rather, he indicates that the most
1161 prevalent approach is **not** to consider the operating income component in the
1162 lead/lag study and **not** to recognize accruals of interest as a source of cash
1163 working capital.⁵ This is the approach used by the Company in the current case,
1164 and what has been approved by the Commission in prior cases.

1165 **Q. Do you have any other concerns with including interest expense in the lead**
1166 **lag study?**

1167 A. Yes. Mr. Garrett makes a simplifying assumption that all interest is collected from
1168 customers, and then paid after it is collected. In many cases, such as the Chehalis
1169 plant, acquired in September 2008, and the various wind projects added to plant in
1170 service in December 2008 and January 2009, interest expense is being incurred
1171 before being collected from customers. The Company began incurring interest
1172 charges when these plants went into service, prior to the inclusion of these costs
1173 in customer rates. Mr. Garrett makes no attempt to quantify the impact of this
1174 long-term lag in recovering interest in his calculation. This would need to be part
1175 of any “comprehensive analysis” of the four parts of return on and return of rate
1176 base as required by this Commission before making any changes to the

⁵ Accounting for Public Utilities, Robert L. Hahne et al, pages 5-22 and 5-23.

1177 calculation of cash working capital.

1178 **Q. What is your recommendation to the Commission regarding the four specific**
1179 **items in question as to whether to include or exclude in a lead lag study?**

1180 A. I recommend the Commission continue its practice of excluding all four items,
1181 namely: (1) depreciation; (2) interest expense; (3) preferred dividends; and (4)
1182 common dividends, from the lead lag study used to calculate CWC. Including any
1183 of these four items in the lead lag study is inappropriate, and would be
1184 inconsistent with Commission practice.

1185 I recommend that the Commission reject Mr. Garrett's proposals on
1186 interest on long-term debt and preferred stock. As explained above, CWC is the
1187 amount of capital required for operations only and should not include non-cash
1188 items such as depreciation and non-operational items such as amounts related to
1189 financing long-term assets. Also, recognition of the cash "lead" for long-term debt
1190 interest is one-sided unless it is accompanied by recognition of a lag for operating
1191 income. The common practice is to recognize that these two items are offsetting
1192 and the proper treatment is to include or exclude both in the working capital
1193 calculation. This is the approach used by the Company in this proceeding.

1194 **Capital Related Adjustments**

1195 **Q. Please explain your understanding of Mr. Croft's proposal to update the**
1196 **composite depreciation rates and recalculate the retirement rates included in**
1197 **the filing.**

1198 A. In Mr. Croft's plant related adjustments, he updates the composite depreciation
1199 rates to use December 2010 plant-in-service balances, instead of using the

1200 composite depreciation rates contained in the filing which are calculated using
1201 June 2010 plant balances. Mr. Croft also recalculates the average retirement rate
1202 to exclude one year, proposing a four year average rather than the five year
1203 average the Company has used in the filing.

1204 **Q. Do you agree with Mr. Croft's proposal to update the composite depreciation**
1205 **rates?**

1206 A. No. The composite depreciation rates included in the filing are developed using
1207 plant-in-service balances by function and factor and the Commission approved
1208 depreciation rates for depreciable property. The depreciation rates were approved
1209 by the Commission in Docket No. 07-035-13 and were effective January 1, 2008.
1210 In the filing, the June 2010 plant balances were used to calculate the composite
1211 depreciation rates to match the June 30, 2010 base period in the case. Since there
1212 has not been a change in the depreciation rates that were previously approved by
1213 the Commission, there is no reason to update the composite depreciation rates to
1214 use December 2010 plant balances. Furthermore, Mr. Croft has not provided
1215 evidence as to why it is better to use the December 2010 composite rates.

1216 **Q. Do you agree with Mr. Croft's proposal to recalculate the average retirement**
1217 **rates?**

1218 A. No. The retirement rates included in the filing are average retirement rates based
1219 on five years of retirement data. The retirement rate for each year is calculated by
1220 taking the retirements divided by the plant-in-service balances. The Company's
1221 average retirement rate calculation included the following five periods: Apr05-
1222 Mar06, Apr06-Dec06, Jan07-Dec07, Jan08-Dec08, and Jan09-Dec09. Mr. Croft

1223 proposes to remove the April 2006 through December 2006 period from the
1224 average calculation since it only includes nine months. The reason this particular
1225 year contains nine months instead of twelve months is due to the Company
1226 moving from a fiscal year ended March to a year ended December. The Company
1227 did not want to give more weight to the January 2006 through March 2006
1228 retirements by including those retirements in two separate periods. Since he
1229 excludes the April – December 2006 period, Mr. Croft's four year average is
1230 missing a period in the middle of the average calculation. This makes it appear as
1231 though he is cherry picking which years to include.

1232 **Q. Do you have any other concerns with Mr. Croft's proposal?**

1233 A. Yes. Virtually all parts of the Company's revenue requirement could be updated,
1234 including inflation rates discussed above. Although it makes sense to update the
1235 rate case for known major changes after the rate case is filed, it would be
1236 administratively difficult to update all components.

1237 **Q. Do you agree with the adjustment proposed by OCS witness Ms. Ramas to**
1238 **reduce April 2011 through June 2012 projected capital additions by 4.34**
1239 **percent?**

1240 A. No. Ms. Ramas compares total Company actual plant additions for July 2010
1241 through March 2011 to the amounts forecasted in the Company's case and
1242 concludes that because the total plant placed in service is 4.34 percent lower than
1243 the amount forecasted for the same period, all forecasted capital additions for
1244 April 2011 through June 2012 included in the Company's filing should be
1245 reduced by 4.34 percent. The Company does not agree with this blanket reduction

1246 to plant additions without regard to individual project status. Ms. Ramas'
1247 adjustment fails to take into consideration projects from the July 2010 through
1248 March 2011 period that have been delayed into the April 2011 through June 2012
1249 period. Ms. Ramas' adjustment also does not take into account new projects that
1250 may have replaced projects that were cancelled or delayed past June 2012. Ms.
1251 Ramas' adjustment decreases capital in every functional category without
1252 consideration as to whether that functional category had more or less placed into
1253 service than what was in the Company's original filing.

1254 **Q. Are there projects in the capital forecast that had been delayed from the July**
1255 **2010 through March 2011 timeframe into the April 2011 through June 2012**
1256 **period?**

1257 A. Yes. In data response DPU 30.3 the Company provided information for projects
1258 that were forecast for July 2010 to March 2011 that were delayed into the April
1259 2011 through June 2012 timeframe. Ms. Ramas' position does not take into
1260 consideration eight projects that were identified in that response that total
1261 approximately \$35 million. Those projects need to be pushed into the later months
1262 of the forecast as those projects have not been cancelled, just delayed.

1263 **Q. Are there any new projects that will be placed into service during the April**
1264 **2011 through June 2012 period?**

1265 A. Yes. In data response DPU 30.3 the Company identified seven projects that were
1266 not included in the original filing, but that are forecast to be placed into service in
1267 the April 2011 through June 2012 period, totaling approximately \$32 million.
1268 Ms. Ramas' position does not take these projects into consideration.

1269 **Q. Do you have any concerns with Ms. Ramas' adjustment to depreciation**
1270 **expense?**

1271 A. Yes. In her adjustment, Ms. Ramas reduces depreciation expense in the mining
1272 function by approximately \$1 million total Company and \$0.4 million Utah
1273 allocated. In the depreciation expense adjustment included in the filing, the
1274 Company did not include an adjustment to mining depreciation expense because it
1275 goes through the cost of fuel (coal) in the net power cost study. Ms. Ramas'
1276 adjustment should be reduced by approximately \$0.4 million Utah allocated to
1277 remove the decrease to mining depreciation expense.

1278 **Q. Please explain the adjustment proposed by UIEC witness Mr. Selecky related**
1279 **to capital additions.**

1280 A. Mr. Selecky proposes to remove post September 21, 2011 capital additions
1281 because the additions are projected to be placed into service after the rate increase
1282 in this case becomes effective.

1283 **Q. Do you agree with Mr. Selecky's adjustment?**

1284 A. No. In its order on Test Period in this docket the Commission states, "we must
1285 also consider the predicted substantial increases in plant investment the Company
1286 forecasts to be necessary in early 2012, particularly the significantly increased
1287 investment projected as necessary for compliance with air quality requirements."
1288 In testimony Mr. Selecky acknowledges the significant capital additions for
1289 pollution control and transmission projects in April 2012, May 2012, and June
1290 2012, but still proposes an adjustment to remove all of those additions. Mr.
1291 Selecky's adjustment appears to be an attempt to overturn the test period order in

1292 this case which approved a test period ending June 2012 with average rate base.
1293 In addition his proposed adjustment is not reasonable because he essentially
1294 ignores over nine months of plant additions in the Test Period. The Company
1295 should be given a reasonable opportunity to recover its costs, and a blanket type
1296 adjustment as Mr. Selecky has proposed does not allow the Company to recover
1297 its costs for those capital investments, and is inconsistent with the Test Period
1298 used in this case. The forecast capital projects to be placed into service
1299 September 22, 2011 through June 30, 2012 will be providing customers with
1300 benefits through the rate effective period and the Company should be allowed the
1301 opportunity to recover those amounts from ratepayers. The capital additions are
1302 necessary and prudent to provide reliable and safe service for our customers.
1303 Failure to include these investments in rates understates the cost of serving
1304 customers and puts significant financial pressure on the Company.

1305 The Company is using 13 month average rate base for the Test Period so
1306 assets that have an in service date at the end of the Test Period will only have a
1307 portion of the amount included. For example, assets that are included with a May
1308 2012 in service date would only have 2/13 of its forecasted amount included in
1309 the case.

1310 **Q. Do you have any issues with the calculation of the adjustment proposed by**
1311 **UIEC witness Mr. Selecky to remove post September 21, 2011 projected**
1312 **capital additions?**

1313 A. Yes. Mr. Selecky's \$974,000 property tax adjustment as shown on Exhibit UIEC
1314 JTS-4 is overly simplistic and incorrect for the following reasons. First, Mr.

1315 Selecky fails to account for the fact that property taxes pertaining to each capital
1316 project with cumulative expenditures in excess of \$5 million as of each year's lien
1317 date are capitalized into the cost of such projects. Accordingly, Mr. Selecky's
1318 proposed adjustment has the effect of removing from property tax expense
1319 amounts not charged to expense. Second, Mr. Selecky fails to account for the fact
1320 that certain projects expected to be placed in service after September 21, 2011
1321 involve the installation of pollution control equipment at the Company's
1322 Wyoming generating plants. Such property is exempt from property taxation in
1323 Wyoming. The estimation processes employed by the Company when estimating
1324 property tax expense take these and other similar items into account.

1325 **Q. Do you have any other comments regarding updating forecasted capital**
1326 **additions with actual capital additions for July 2010 through March 2011?**

1327 A. Yes. In the original filing removal costs were included in some of the Company's
1328 capital project forecasts. However, actual removal costs reduce the accumulated
1329 depreciation reserve balance, thus increasing rate base, but these costs were not
1330 included as plant additions in the Company's response to DPU 30.3. Actual
1331 removal costs for July 2010 through March 2011 related to generation projects
1332 total \$23 million. When removal costs are included, as of the end of March 2011
1333 actual plant additions are only \$47 million lower than forecasted, rather than \$70
1334 million. Since removals are a new issue in the rate case the Company has not
1335 included those removals in its rebuttal position. The Company has provided
1336 information here about the removals to support the Company's assertion that its
1337 capital project rebuttal position is reasonable and conservative considering the

1338 Company's rebuttal position could be increased by \$23 million. This is further
1339 evidence why Ms. Ramas' adjustment to reduce the April 2011 to June 2012
1340 capital additions by 4.34 percent and Mr. Selecky's adjustment to remove over
1341 nine months of capital should both be rejected.

1342 The Company is continually analyzing the capital needs of the electrical
1343 system to determine which investments are required to maintain and provide
1344 reliable service to its customers. It is not uncommon to change priorities in order
1345 to benefit the entire system. This may involve accelerating a project because of a
1346 critical need, which may cause a delay in other projects, thus changing the mix of
1347 plant additions from what was included in the original rate case filing.

1348 The approach taken by the DPU related to the April 2011 to June 2012
1349 forecasted capital additions is more appropriate for this case because it looks at
1350 individual project forecasts and timing. Ms. Ramas' position disregards possible
1351 changes in the timing of projects being placed into service and should be rejected.
1352 Mr. Selecky's position does not allow the Company to recover costs for prudent
1353 capital investments which will provide benefits to customers through the rate
1354 effective period.

1355 **Q. UIEC witness Dennis Peseau proposed an adjustment to remove 50 percent**
1356 **of the Populus to Terminal transmission line from rate base. Does the**
1357 **Company accept the adjustment, and did he calculate his adjustment**
1358 **correctly?**

1359 A. No. As stated in the rebuttal testimony of Company Witness Mr. John Cupparo,
1360 the Company rejects Mr. Peseau's adjustment completely. In addition, Mr.

1361 Peseau has not correctly calculated his adjustment to remove 50 percent of the
1362 Populus to Terminal project from this filing. It appears as though Mr. Peseau has
1363 used a rate base amount of \$819 million for the project which was provided in a
1364 data response in the Company's recent Wyoming general rate case. This amount
1365 is different than the rate base amount included for the Populus to Terminal project
1366 in the Utah general rate case. Mr. Peseau also has not taken into account the
1367 Company's use of 13 month average rate base in this filing. It also appears as
1368 though Mr. Peseau has assumed no bonus depreciation for the Populus to
1369 Terminal project, which is also incorrect. Mr. Cupparo and Mr. Gerrard provide
1370 additional testimony regarding the impropriety of Mr. Peseau's adjustment.

1371 **Klamath Hydroelectric Settlement Agreement**

1372 **Q. Please summarize the Company's position related to the Klamath**
1373 **Hydroelectric Settlement Agreement ("KHSA").**

1374 A. The KHSA represents a beneficial outcome to a complex and challenging process
1375 resolving the issues surrounding the Company's assets located in the Klamath
1376 basin region. The rebuttal testimony of Mr. Dean S. Brockbank provides more
1377 detail on the Company's policy relating to Klamath.

1378 **Q. In the rebuttal testimony of Mr. Brockbank, he states that the KHSA benefits**
1379 **all of the Company's customers. Can you provide support for his statement?**

1380 A. Yes. The Company compared the cost of the KHSA with the costs expected under
1381 a conservative relicensing scenario. Since the costs of relicensing are highly
1382 uncertain, the Company developed a baseline relicensing case against which the
1383 economics of the KHSA were compared. The baseline relicensing case relies

1384 heavily on the costs and data developed as part of the FERC Final Environmental
1385 Impact Statement (“FEIS”).

1386 **Q. How was the analysis structured?**

1387 A. The analysis evaluated the present value revenue requirement (“PVRP”) of the
1388 stream of costs under the KHSA and compared it against the PVRP of the stream
1389 of costs under the baseline relicensing scenario. The analysis covered a 44-year
1390 period beginning in 2010 – this equates to a 40-year license beginning in 2014.
1391 The results of this analysis are summarized in Confidential Exhibit RMP__(SRM-
1392 5R). The analysis was shared with Utah parties at a technical conference on
1393 February 15, 2011.

1394 **Q. Does the KHSA result in a fair and balanced outcome to the Company’s**
1395 **Utah customers?**

1396 A. Yes. Based on the outcome of this conservative analysis, the KHSA results in a
1397 PVRP that is below the cost of relicensing. More importantly, customers are
1398 protected from the risks and liabilities that exist absent an agreement among the
1399 parties. These risks include: (1) far higher costs under final terms and conditions
1400 for relicensing; (2) the inability to secure state and federal approvals for
1401 relicensing; (3) continued litigation related to endangered species act
1402 requirements and water quality issues; and (4) early shut-down and removal of the
1403 project. In the end, the terms of the KHSA allow the Company to protect its
1404 customers in the long term from the potential economic impact and risks of
1405 relicensing.

1406 **Q. What adjustments are recommended by the intervening parties with regards**
1407 **to the KHSA?**

1408 A. DPU witness Dr. Powell opposes the accelerated depreciation of the existing
1409 Klamath assets, suggests a 20 year depreciation life of the relicensing costs, and
1410 recommends situs treatment of the surcharge under the Rolled In allocation
1411 methodology. UAE witness Mr. Higgins opposes the accelerated depreciation of
1412 the existing Klamath assets and recommends Utah customers not pay for the
1413 KHSA surcharge. OCS witness Ms. Beck recommends a complete disallowance
1414 of all KHSA related items.

1415 **Q. Does the Company agree with Dr. Powell and Mr. Higgins contention that it**
1416 **is premature to change the depreciation rates for existing Klamath**
1417 **hydroelectric project assets?**

1418 A. No. Mr. Brockbank responds to Dr. Powell's and Mr. Higgins' proposals and
1419 supports the Company's position based on the details of the KHSA. The
1420 Company continues to request the Commission's approval in this case of an
1421 accelerated depreciation schedule that would depreciate the Klamath facilities on
1422 a straight-line basis such that the net book value reaches zero by December 31,
1423 2019, prior to possible dam removal.

1424 **Q. What is the impact on this case related to accelerating the depreciation of the**
1425 **existing Klamath facilities?**

1426 A. Page 8.12.2 of Exhibit RMP____(SRM-3) that accompanied my direct testimony
1427 details the depreciation expense calculation for existing Klamath facilities, with
1428 the accelerated rates effective January 1, 2011. The accelerated rates result in

1429 additional Test Period depreciation expense of approximately \$4.5 million on a
1430 total Company basis, or \$1.9 million on a Utah-allocated basis in this case. If the
1431 change to depreciation rates is postponed, the impact on rates will increase
1432 exponentially because of the fewer number of years to depreciate the plant.

1433 **Q. Dr. Powell supports his recommendation by saying, “Since the Company has**
1434 **stated it plans on filing annual rate cases for the foreseeable future, the**
1435 **Company can introduce the Klamath issue in the next rate case with little**
1436 **incremental impact on rates”. Why is this not preferable treatment from the**
1437 **perspective of Utah ratepayers?**

1438 A. The timing of the Company’s future rate cases is not a valid reason to delay the
1439 accelerated depreciation. With a terminal date for the Klamath facility specified
1440 in the KHSA, delaying the recovery only shortens the time-span for which costs
1441 are recovered and increases the impact to customers.

1442 **Q. Dr. Powell recommends the depreciation life of the relicensing costs be**
1443 **extended from 10 years as requested by the Company to 20 years. Is this**
1444 **beneficial to ratepayers?**

1445 A. Under the KHSA, the Klamath dam will be operational through the
1446 decommissioning in 2020. Setting the depreciation of the assets to be fully
1447 depreciated by 2020 assigns the costs of the Klamath project to the customers
1448 who will benefit from the project prior to its decommissioning and prevents those
1449 costs from being pushed to future ratepayers who will no longer be benefitting
1450 from the resource. Ratepayers today might benefit from a longer depreciation
1451 life, but this benefit comes at the expense of future ratepayers. His

1452 recommendation misaligns the benefits with the costs causing intergenerational
1453 subsidies.

1454 **Q. Please explain Dr. Powell and Mr. Higgins' positions on how the surcharge
1455 and removal costs should be allocated.**

1456 A. Both Dr. Powell and Mr. Higgins recommend the removal costs be directly
1457 assigned to California and Oregon under the Rolled In methodology.

1458 **Q. Are these costs appropriately allocated under the definition of the Rolled In
1459 methodology?**

1460 A. Yes. Under the Rolled In methodology, the costs associated with a system
1461 resource should be allocated system-wide. Since Klamath is a system resource,
1462 system allocation of its costs is both appropriate and reasonable as it is no
1463 different than any of the Company's other hydroelectric generation facilities on
1464 the west side of the system. The parties in this case all advocate for the Rolled In
1465 methodology. Under their prescribed methodology, the costs associated with the
1466 KHSA represent system costs.

1467 **Q. Do you agree that the revenue collected from Oregon and California
1468 ratepayers related to the KHSA surcharge should be allocated to Utah's
1469 ratepayers?**

1470 A. No. The removal of the Klamath project as described by Mr. Brockbank will be
1471 done because it is in the best interest of all customers, not just customers in
1472 Oregon and California. The revenue collected under the Oregon and California
1473 surcharge is state specific revenue collected under a separate tariff. Revenue
1474 collected in other states is irrelevant to the costs that are allocated to Utah under a

1475 multi-jurisdictional allocation methodology. Just as the revenues collected from
1476 Utah ratepayers does not affect the costs that are allocated to other states. KHSA
1477 dam removal costs are system costs that are appropriately allocated to Utah under
1478 the Rolled In methodology.

1479 **Q. Please summarize the OCS position on the costs associated with the KHSA.**

1480 A. The OCS contends that KHSA costs should not be included in this rate case
1481 because the costs 1) were incurred to satisfy regional interests; 2) are uncertain
1482 due to unmet conditions contained within the KHSA; and 3) have not received
1483 adequate regulatory review. The first and second concerns listed above are
1484 addressed in detail in the rebuttal testimony of Mr. Brockbank. I will address her
1485 third concern.

1486 **Q. Is Ms. Beck's statement that the KHSA and its applicable costs have not**
1487 **received adequate regulatory review a valid argument?**

1488 A. No. Through the MSP Docket No. 02-035-04, the Klamath issue has been an
1489 ongoing subject of discussion. Since the Company filed for approval of the 2010
1490 Protocol methodology, Klamath has been even more heavily addressed. The
1491 Company held a technical conference with Utah parties on February 15, 2011
1492 focusing on the KHSA. In addition, the Company has responded to significant
1493 discovery in Utah with regards to Klamath. Delaying the recovery of the KHSA
1494 will only shorten the period over which the costs are recovered.

1495 **FERC Wheeling revenues**

1496 **Q. Is the Company's FERC transmission rate case filing reflected in the revenue**
1497 **credits proposed for the Test Period in this case?**

1498 A. No. The Company's transmission rate case, filed with FERC on May 26, 2011,
1499 under docket number ER11-3643, proposes updated wholesale rates for
1500 transmission and other ancillary services provided under the Company's Open
1501 Access Transmission Tariff ("OATT"). To date, no procedural schedule for
1502 discovery, settlement or hearing has been set. Due to often lengthy settlement
1503 processes at FERC to resolve rate cases, the Company is not able to calculate the
1504 date FERC will issue an order approving the Company's request for OATT rate
1505 changes. It is possible that FERC will allow the Company's proposed rate
1506 changes to be made effective prior to issuance of an order; however, any such
1507 rates would be subject to refund pending the conclusion of the FERC proceeding.
1508 As a result, the Company has not proposed any wholesale revenue credit
1509 adjustments for this case ensuing from the transmission rate case filing.

1510 Since the Company does not know the amount or timing of a FERC
1511 decision and the subsequent effective date for the approved rates, the Company
1512 proposes deferring Utah's share of any rate increase granted by FERC until the
1513 next Utah rate case. The Company does not anticipate this amount to be
1514 significant. The Company included in its transmission rate case filing a customer
1515 impact statement which shows OATT revenues using the proposed rates applied
1516 to historic loads. The impact statement indicates approximately \$1.3 million in
1517 incremental annual third-party transmission revenues and \$1.7 million in
1518 incremental annual ancillary service revenues under the proposed rates, exclusive
1519 of any short-term or non-firm revenues. On a Utah-allocated basis, assuming the
1520 new rates are permitted to be made on an interim basis effective January 2012,

1521 would only amount to approximately \$650,000 Utah allocated in the Test Period
1522 assuming the full requested increase is granted.

1523 **REC Revenue Deferral – Post Docket 10-035-124**

1524 **Q. Did any of the parties to this case discuss REC deferral or tracking**
1525 **mechanisms?**

1526 A. Yes. Ms. Salter for the DPU and Ms. Ramas for the OCS both recommended
1527 mechanisms to account for the difference between actual REC revenues and the
1528 amounts included in rates from this case. According to Ms. Salter:

1529 “the Division is recommending a REC Tracker be established in
1530 order to help alleviate the fluctuation the Company is seeing in its
1531 market REC price.... To simplify the process, the tracker could be
1532 structured in a way that filings and rate adjustments would follow
1533 the Company’s recently implemented energy balancing account
1534 (EBA). This would enable the REC revenues to be trued up at the
1535 same time as the EBA expenses. The Division believes the best
1536 approach would be to have the two programs run parallel to each
1537 other but reported in separate dockets.”⁶

1538 Ms. Ramas made the following proposal:

1539 “I recommend that RMP be required to record the difference
1540 between the amount of REC revenues approved by the
1541 Commission in this case for inclusion in rates and the actual REC
1542 revenues realized, with any differences being recorded in a
1543 regulatory deferral account.... At the time of the next rate case
1544 following this case, any deferred balance would be amortized as
1545 part of the revenue requirement.”⁷

1546 **Q. What is the Company’s position regarding the DPU and OCS proposals?**

1547 A. The Company agrees that due to the current uncertainty in the REC market a
1548 mechanism would be appropriate, and would urge the Commission to adopt one
1549 of the proposals.

⁶ Direct testimony of Brenda Salter, page 13, lines 233 – 241.

⁷ Direct testimony of Donna Ramas, page 36, lines 787 – 790 and 799 – 801.

1550 **Q. What is the Company's preferred approach?**

1551 A. Although the Company believes both proposals have merit and are acceptable, the
1552 Company would prefer the DPU approach because it outlines the timing of REC
1553 filings and aligns rate changes with those of the Energy Balancing Account
1554 ("EBA"). The reason for this preference is because when the Company files the
1555 next rate case it may only have a few months of actual data, and would need to
1556 provide an estimate for the remaining time until the new rates from the next case
1557 go into effect. Although some of the estimates could be trued up during the case,
1558 the ultimate true up would need to be in a later rate case filing. For this reason,
1559 the Company would prefer the DPU approach using the same filing dates as the
1560 EBA.

1561 **REC Revenue and Net Power Cost Deferrals**

1562 **Q. What is the Company's position regarding net power cost (**
1563 **"NPC") and REC deferrals from February 2010 through September 2011?**

1564 A. As described in my supplemental direct testimony on deferred accounts, the
1565 Company believes that starting the amortization of both the deferred NPC and
1566 deferred REC accounts simultaneously is in customers' interest.

1567 **Q. Was the amortization of the REC and NPC deferred balances addressed in**
1568 **the intervenor direct testimony in this rate case?**

1569 A. Yes. The amortization of the deferred REC balance was addressed in the
1570 testimony from the OCS and UAE, but neither they nor any other party addressed
1571 the issue of the deferred NPC balance.

1572 **Q. When did the Company begin deferring Utah allocated REC revenue and**
1573 **deferred NPC?**

1574 A. Pursuant to the Commission's July 14, 2010 Report and Order on Deferred
1575 Accounting Stipulation in Docket Nos. 09-035-15 and 10-035-14, the Company
1576 has deferred incremental NPC in a deferred NPC account from February 18, 2010
1577 and incremental REC revenue in a deferred REC account from February 22, 2010.

1578 **Q. What position was taken by parties on the amortization of the deferred REC**
1579 **balance in their testimony in this case?**

1580 A. The OCS and UAE each requested that the Commission determine the ratemaking
1581 treatment of the balance in the deferred REC account as part of this case. The
1582 OCS requested that the balance (as reported by the Company on the last day of
1583 hearings in the case) be amortized over a period of three years starting on
1584 September 21, 2011, with the amount trued up to actual accruals through
1585 September 20, 2011. UAE requested that the balance that had accrued in the
1586 deferred REC account through December 31, 2010, be amortized from September
1587 21, 2011 through September 20, 2012 and that the balance accruing from January
1588 1, 2010 through September 20, 2010 be amortized from September 21, 2012
1589 through September 20, 2013.

1590 **Q. What is the magnitude of the REC and NPC deferrals recorded by the**
1591 **Company?**

1592 A. Confidential Exhibit RMP__(SRM-6R) shows the actual deferrals for calendar
1593 year 2010, and projected deferrals for calendar year 2011. The balance in the
1594 deferred REC account from February 22, 2010 through December 31, 2010 was

1595 approximately \$39 million. The Utah-allocated deferred NPC from February 18,
1596 2010 through December 31, 2010 is approximately \$54 million, prior to any
1597 consideration of use of the Rolled In allocation method as discussed in the EBA
1598 Order.

1599 The Company estimates that as of September 21, 2011, the date rates set
1600 in this general rate case will go into effect, the balance in the deferred REC
1601 account will be approximately \$37 million, and the balance in the NPC deferral
1602 account will be approximately \$157 million.

1603 **Q. Does the Company believe that it would be in the customers' or Company's**
1604 **best interest to start amortization of the REC deferral and not the NPC**
1605 **deferral?**

1606 A. No. As described in my supplemental direct testimony, if the Commission
1607 determines the ratemaking treatment of the balance in the deferred REC account
1608 as part of this case, it should also determine the ratemaking treatment of the
1609 balance in the deferred NPC account as part of this case. To provide customers
1610 with a potential rate sur-credit based on the deferred REC account balance while
1611 holding the potential rate surcharge associated with the deferred NPC account
1612 balance that accumulated over the same time period for later treatment would not
1613 be appropriate and would simply delay the recovery of the deferred NPC to a later
1614 period when there may not be an offsetting credit.

1615 **Q. In responses to your supplemental testimony and the Company's Motion for**
1616 **Determination of Ratemaking Treatment of Deferred Accounts, other parties**
1617 **have argued that the Company should not be allowed to recover the Deferred**
1618 **NPC Account as a matter of law. Do you agree?**

1619 A. No. I do not intend to argue the legal issues in this testimony. However, I believe
1620 it would be appropriate to respond to factual issues underlying the positions of the
1621 other parties.

1622 There is no underlying factual difference between the Deferred NPC
1623 Account and the Deferred REC Account. Both are the result of the fact that the
1624 Company, the parties and the Commission were unable to accurately predict the
1625 amount of NPC and REC revenue that would be incurred during the period rates
1626 set in the last general rate case have been in effect. The differences between the
1627 amounts included in rates and the amounts incurred were significant and
1628 substantial in both cases. Neither constitutes a normal deviation from projections
1629 of amounts included in rates. The fact that the Commission granted deferred
1630 accounting for both amounts already reflects these facts.

1631 The issue before the Commission in determining the ratemaking treatment
1632 of the deferred accounts is whether the amounts deferred are reasonable and
1633 prudent. This issue is no different for the Deferred NPC Account than it is for the
1634 Deferred REC Account. Parties have raised questions in their direct testimony
1635 regarding the prudence of certain items within the Company's NPC. Parties have
1636 also raised questions about whether the Company was prudent in its management
1637 of its RECs. Other witnesses for the Company have responded to these issues in

1638 their rebuttal testimony. These issues are the same issues that the Commission
1639 will address in deciding whether recovery of all or some portion of the deferred
1640 accounts is appropriate.

1641 **Q. Does this conclude your Testimony?**

1642 A. Yes.